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REBUTTAL TESTIMONY of

RAYMOND D. BLIVEN and NANCY PARKER

Witnesses for Bonneville Power Administration

SUBJECT: POWER POLICY

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-06.

A. My name is Nancy Parker, and my qualifications are contained in BP-14-Q-BPA-51.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to address concerns raised by parties regarding power rates policy issues and the Oversupply rate.

Section 2: Supportive Comments

Q. Did any party's direct case support elements of BPA Staff's Initial Proposal for power rate schedule provisions?

A. Yes. Joint Party 3 (JP03) and Western Montana G&T (Western Montana) submitted comments supporting aspects of BPA Staff's proposals.

Q. What aspects of your proposal did they support?

A. JP03 stated that it appreciates "the creativity that staff has shown in anticipating potential problems and providing workable solutions in the context of the Tiered Rate Methodology … and the Contract High Water Mark … contracts." Brawley and Carr, BP-14-E-JP03-01, at 4. JP03 lists its support for the following aspects of Staff's Initial Proposal:

1. The New Resource Energy Shaping Service and True-Up adjustment for New Large Single Loads taking the NR Energy Shaping Service.
2. The case-by-case broadening of those cases where the Unanticipated Load Service may be provided.
3. The specification of the Load Shaping True-Up payment options in the General Rate Schedule Provisions.
4. The language changes for the Low Density Discount and the Irrigation Rate Discount.
5. The demand charge adjustment for extreme load shifts.
6. The demand charge adjustment for recovery peaks.
7. The adjustment to power bills if a customer does not retain some or all of its Provisional CHWM.
8. The Tier 2 Remarketing proposal.
9. The Resource Remarketing Service for BPA customers' non-Federal resources.

Id. at 4-5. JP03 states that the foregoing provisions are of particular interest to its component members and urges the Administrator to adopt them at the end of the rate proceeding. *Id.* at 5. JP03 also supports Staff's Initial Proposal for the General Transfer Agreement Service (GTA) delivery charge rate based on actual costs for GTA service. *Id.* at 13-14.

Q. Do you have any response to JP03's statement of support?

A. We appreciate that they made the effort to note the changes and respond positively. Some of the proposals are being made in anticipation of issues and situations that may not arise. Even though elements of the proposals may never be used, anticipating potential problems and providing workable solutions is much easier now when the rate schedules are being prepared than when a need may arise and we have to deal with it within the confines of the rate schedules. We will continue working with our customers and their representatives to address other potential problems as they come to light.

Q. What aspects of Staff's proposals does Western Montana support?

A. Western Montana supports the proposal to decouple the GTA delivery charge from the Utility Delivery Charge, Lukas, BP-14-E-WM-01, at 3-4, and to set the GTA Delivery Charge based on the average transfer costs of transfer service customers, *id.* at 5.

Q. Do you have any response to Western Montana's statement of support?

A. We appreciate the positive feedback. The GTA Delivery Charge issues raised in parties' direct cases are further addressed in the BPA rebuttal testimony of Yokota and Miller, BP-14-E-BPA-41.

Section 3: Power Rate Increase

Q. Did parties raise any general concerns with the Initial Proposal rate increase?

A. JP03 and Joint Party 5 (JP05) stated that Staff's Initial Proposal rate increase would be "a challenge and difficult for local utilities to absorb," Brawley and Carr, BP-14-E-JP03-01, at 2, and "extremely burdensome," Deen and O'Meara, BP-14-E-JP05-01, at 2. JP03 and JP05 cited the continued weakness of the Northwest economy and its effects on utilities and consumers as major factors in their concern. Brawley and Carr, BP-14-E-JP03-01, at 2-3; Deen and O'Meara, BP-14-E-JP05-01, at 2. WPAG states "[o]ver the last several rate periods BPA's costs have continued to rise even in a depressed economy that has many of its customers reducing costs." Saleba *et al.*, BP-14-E-WG-01, at 7.

Q. What did parties propose to address the proposed rate increase?

A. JP03 recommends that BPA re-examine its expenses "to determine whether the agency can obtain more savings and whether the agency can program further debt service or repayment adjustments." Brawley and Carr, BP-14-E-JP03-01, at 3. JP03 also recommends that "BPA and the Non-Slice customers take a close review of secondary revenue forecasts as the agency approaches the final determinations in this proceeding." *Id.* JP03 suggests that BPA convene a meeting in early May 2013 to discuss the balance between risk and the effect on non-Slice rates, to be held in conjunction with suggested meetings to address FY 2013 risks and their effect on FY 2014 and FY 2015 rates. *Id.* at 3-4. JP03 further recommends a new annual process to be held in the spring of every operating year to review and discuss risk issues for the next rate year. *Id.* at 11.

JP05 states that "BPA needs to consider what needs to happen if market power prices stay low for a long time." Deen and O'Meara, BP-14-E-JP05-01, at 5. JP05 states that "if power prices stay low, BPA is going to have to more tightly restrain its expenditures to limit the degree to which BPA is more expensive than market." *Id.*

WPAG states that, if financial circumstances deteriorate significantly in 2013, BPA should hold discussions with customers including identification of further cost reductions through an IPR-2 [Integrated Program Review second phase]. Saleba *et al.*, BP-14-E-WG-01, at 6. WPAG also states that BPA should tie "any CRAC adjustment or inclusion of PNRR in rates with BPA cost reductions." *Id*. Finally, WPAG recommends that BPA immediately commence an IPR-2 to identify cost reductions that could be implemented in conjunction with a CRAC or PNRR so that the potential shortfall in secondary revenue is not borne entirely by customers. *Id*. at 7.

Q. How do you respond to the concern about the level of the rate increase?

A. BPA is acutely aware of the effect of its rates on customers. Leading up to the rate case, BPA and interested parties undertook many months of IPR strategic program discussions. The outcome was the program spending levels that form the basis for the proposed BP-14 rates. BPA started the IPR with a forecast 12 to 20 percent power rate increase and closed out the process with an expectation of a rate increase of less than 10 percent. In the IPR close-out letter (November 6, 2012), BPA stated: "As FY 2013 financial results unfold, BPA will remain open to revisiting spending levels in an 'IPR-2' process, if necessary to maintain BPA's long-term goals."

We have taken the parties' concerns to BPA's management. Management also is concerned about the level of the rate increase and BPA's exposure to further revenue declines and wants the region to know that BPA is carefully managing its costs. However, they are not anticipating the need for an IPR-2 process at this time. Although we are experiencing lower secondary energy revenues than in the past, BPA must continue to protect the long-term asset value of the aging Federal Columbia River Power System hydropower and nuclear generating resources.

Finally, we are concerned that if BPA and stakeholders take too long in IPR-2 discussions, the delays may limit our ability to reflect the results in the Final Proposal.

Q. What other avenues do parties have to review BPA's costs?

A. BPA established the Quarterly Business Review (QBR) process to review BPA financial management and performance during the operating year. We recommend the parties suggest any changes they would find helpful at the next QBR.

Q. How do you respond to the request to review secondary revenue forecasts prior to the Final Proposal? (Brawley and Carr, BP-14-E-JP03-01, at 3.)

A. We recognize that secondary revenues are a critical factor in the Final Proposal rate level, and BPA is willing to accommodate this request. We will work with parties to find an appropriate time in the procedural schedule to conduct a meeting for all rate case parties to discuss secondary revenue forecasting. Prior to this meeting, we will ask parties the type of information that would be useful for this discussion.

Q. JP05 states that BPA needs to consider what needs to happen if market power prices stay low for a long time. Deen and O'Meara, BP-14-E-JP05-01, at 5. Please respond.

A. We raised this concern with BPA's stakeholders a year ago. We held meetings to begin exploring this question. As of last summer, participants suggested that the discussions be tabled until after this rate proceeding. We expect to resume these discussions in the autumn of this year.

Q. WPAG states, "Over the last several rate periods BPA's costs have continued to rise even in a depressed economy that has many of its customers reducing costs." Saleba et al., BP-14-E-WG-01, at 7. WPAG notes that "absent BPA's one time debt management actions, BPA's costs would be $160 million higher over the next two years than during the current rate period." Id. Please respond.

A. The spending levels that WPAG cites were those established in the IPR with all participants fully informed of expected reductions in market revenues and other revenue requirement changes. The IPR process resulted in an increase in costs included in power rates of $80 million compared to BP-12, which translates into approximately a 4 percent rate increase, all other things being equal and without counting the offsets from debt management actions. Most participants believed these program levels were prudent despite the depressed economy.

Q. WPAG argues that BPA should make its contribution to solving this revenue shortfall with additional cost reductions tied to the CRAC or inclusion of PNRR, so that the solution is not borne entirely by BPA's customers. Id. Do you believe that the shortfall in secondary revenue is borne entirely by customers?

A. No. During the IPR process, we provided rate estimates that included the secondary revenue shortfall so that spending decisions could be considered with the revenue outlook in mind. During the IPR process, BPA and stakeholders worked together to provide $73 million of debt management savings that would offset the expected $115 million revenue shortfall. Thus, we believe that the IPR has already considered the revenue shortfall in setting the spending targets used in the revenue requirement for this rate case. Ultimately, however, BPA's customers bear the costs of revenue shortfalls, whether the immediate response is cost reductions or a rate increase. Cost reductions may directly affect the reliability and quality of service that customers receive from BPA. BPA recognizes that a balance must be struck between program cost reductions and risks that come with such reductions.

Section 4: Cost Recovery Adjustment Clause (CRAC) versus Planned Net Revenues for Risk (PNRR)

Q. In your direct testimony, Bliven and Parker, BP-14-E-BPA-11, at 20-21, you requested parties' input regarding risk mitigation choices that may arise in the Final Proposal if FY 2013 conditions deplete Power Services' financial reserves. Did parties respond?

A. Three parties responded: JP03, JP05, and WPAG. JP03 states that BPA Staff's proposal to conduct further discussions regarding risk mitigation in the Final Proposal "is problematic because it forces customers to wait until much of the rate case is over before having a discussion about risk …." Brawley and Carr, BP-14-E-JP03-01, at 10. JP03 argues that "[u]tilities would have too little time to react" to increased rates due to PNRR or a CRAC that triggers at the start of the rate period. *Id.* at 11. JP03 states that "[u]ntil the issue is further clarified through discussions with the customers, BPA should not add any PNRR to its revenue requirement." *Id.* JP03 suggests a "workshop process in the spring of 2013" and "in the spring of every operating year to conduct a review and discussion of all the factors relevant to risk issues for the next rate year." *Id.*

Q. What is the response from JP05?

A. JP05 identifies procedural issues, claiming that "BPA seems to be reserving the unilateral right to introduce a PNRR and adjust the CRAC after all evidence has been presented in the rate case," with no parameters given on the potential PNRR and adjusted CRAC, and no opportunity for party review. Deen and O'Meara, BP-14-E-JP05-01, at 6-7. JP05 also states that customers face "rate shock" due to the proposed "Day 1" CRAC design. *Id.* at 7. JP05 suggests that "any shortfall be recovered over two years (50% per year) …," *id.*, to eliminate the rate shock problem and the "procedural deficiencies" of Staff's Initial Proposal, *id.* at 8. Like JP03, JP05 states that BPA should consult with customers if water/revenues worsen in FY 2013. *Id.* at 9.

Q. *What is the response from WPAG?*

A. Like JP03 and JP05, WPAG advocates a "short, collaborative process" that occurs after second quarter review results are published in the case of a significant decrease in forecast Power Services financial reserves for the end of FY 2013. The discussions would be "to determine what tools should be used to address the situation." *Id.* at 6. WPAG is particularly concerned that any CRAC BPA considers using in such a situation should be collaboratively developed to address current needs rather than being based on past needs. *Id.* at 6-7. In addition, WPAG states, BPA should "immediately commence an IPR 2 to find further cost reductions that could be implemented in conjunction with a CRAC or PNRR." *Id.* at 7.

Q. *Please comment on the responses.*

A. We stated earlier that BPA "will continue to keep its customers and rate case parties apprised of its financial conditions and expectations for a 2014 CRAC as FY 2013 progresses. Conditions may warrant a further discussion about risk mitigation choices for the final rates." Bliven and Parker, BP-14-E-BPA-11, at 21. Parties' requests for meetings in early May are consistent with this. There is a QBR currently scheduled for April 30; as WPAG suggests, this would be an appropriate time to consider BPA's 2013 revenue condition and remaining risk exposure for the year. It would likely not be a constructive use of parties' time to meet until updated water year and financial information becomes available to meaningfully revise Initial Proposal estimates. These will be available at the April QBR. The estimates at that time will be more indicative of information that will be used to prepare the Final Proposal.

Q. The Initial Proposal projections showed a 12 percent chance of a FY 2014 CRAC. Does Staff have any updated estimates of the probability of a FY 2014 CRAC?

A. Yes. Based on preliminary estimates, the probability of a CRAC triggering has not increased since the Initial Proposal projections. As stated above, BPA intends to update this estimate at the April QBR and provide it to the parties at that time. If further discussion is needed, BPA will accommodate parties' interest in meeting to collaboratively discuss the rate increase and risk mitigation.

Q. Do you agree with JP05 regarding its concern about potential procedural issues associated with the possibility of adding PNRR for the Final Proposal? (Deen and O'Meara, BP-14-E-JP05-01, at 6-7.)

A. Although procedural issues are legal in nature, we would like to comment on the "technical" aspect. As parties themselves have pointed out, the potential need for risk mitigation is better understood as time passes and major factors of water and market conditions become known. This is particularly true during the year the rate proceeding is being conducted (*e.g.*, FY 2013), leading up to the actual rate period. If these conditions were known when preparing the Initial Proposal, BPA and parties could undertake a robust discussion throughout the rate case. As it is, we do not know whether we need to undertake that discussion until later in the rate case schedule. Therefore, in the Initial Proposal, Staff included information based on what we knew at that time (*e.g.,* 12 percent probability of an FY 2014 CRAC) and requested parties' input on the trade-off between the two major risk mitigation techniques, PNRR and CRAC.

We understand JP05's concern about procedural issues, but pressing this issue will remove from the toolbox a potential valuable tool for dealing with risk mitigation; BPA and rate case parties have a direct interest in keeping options open. Our intent in raising the issue was not to provide a unilateral right for BPA to do whatever it wanted with PNRR and CRAC. Holding collaborative discussions when we all have better information appears to be a good approach to dealing with this challenging issue. The alternative would have been to include a PNRR placeholder in the Initial Proposal, thus allowing parties the opportunity to discuss and challenge the question. This strategy would have made the Initial Proposal rate increase appear even higher than it was, with a good chance of removing the PNRR because of the very high likelihood that it would not be needed in final rates.

Rather than overstate the rate increase in the Initial Proposal, we believed the better option was to reflect our best forecast of future conditions on final rates, that is, no PNRR, and to raise the potential use of CRAC or PNRR options in our testimony.

We disagree that we are proposing to introduce PNRR or adjust the CRAC with "no parameters given." The methodology used for calculating needed amounts of PNRR and for calculating the CRAC threshold are described in detail in direct testimony, Lovell *et al.*, BP-14-E-BPA-15, at 35-37, and in the Power Risk and Market Price Study, BP-14-E-BPA-4, at 74-81. This methodology provides all of the parameters for introducing PNRR or adjusting the CRAC threshold. We are proposing to update only the data that serves as inputs to the methodology, *e.g.*, market prices and FY 2013 financial results as available.

Q. Do parties favor a CRAC over PNRR?

A. WPAG explains that they have historically supported use of the CRAC instead of PNRR given the choice of a possible rate increase versus a certain rate increase. However, they "do not have enough information to say whether including PNRR in power rates would be preferable to a higher probability of the CRAC triggering at the outset of the rate period." Saleba *et al.*, BP-14-E-WG-01, at 5.

JP05 argues that the CRAC is superior to PNRR because it is based on "an actual shortfall, rather than just a forecast that a shortfall may be incurred." Deen and O'Meara, BP-14-E-JP05-01, at 8-9. JP05 argues, however, that BPA has created the problem of a large potential "Day 1" CRAC. *Id.* at 7. JP05 states that BPA's proposal to recover "the initial $100 million shortfall in one year is overly severe and burdensome and will lead to unnecessary 'rate shock.'" *Id*. JP05 proposes that any shortfall in power reserves be recovered over a two-year period, 50 percent in each year. *Id*.

JP05 also argues that the two-year CRAC is consistent with the terms of the Treasury borrowing facility. Staff addresses this issue in Lovell and Mandell, BP-14-E-BPA-39.

Q. Please respond to JP05's proposal of a two-year CRAC.

A. We have no substantive issue with JP05's proposal, other than to note that its proposal would result in the same effect on rates as the PNRR solution we inquired about in our direct testimony: it would spread the cost recovery over a two-year period. We are unsure why JP05 argues that PNRR is inappropriate and then advocates for a mechanism that has virtually the same impact on rates. This is not a question of using forecast data rather than actual data—the application of the CRAC or PNRR would occur at the same time, no matter which solution is employed.

Q. Please respond to JP03's and JP05's concern about rate shock.

A. We understand the concerns with inserting an unexpected rate increase with little time for customers to react. We do note that the so-called "Day 1" CRAC is determined at the same time as BPA publishes its Final Proposal rates. Thus, whether PNRR or CRAC is used to address FY 2013 shortfalls, customers will have the same notice about the rate level that will begin on October 1. Furthermore, as we state above, we will keep customers informed through the QBR and other meetings as necessary between now and the end of July. Our purpose in this discussion is to keep rates at the lowest level possible while being fully cognizant of the current financial situation.

Generally, when implementing risk mitigation, time is the important factor. The longer we wait, the less we need to rely on forecasts rather than actual results. As JP05 notes, responding to an actual shortfall is superior to a forecast shortfall. Deen and O'Meara, BP-14-E-JP05-01, at 8-9. BPA does not have that luxury, because rates are set in advance based on forecast data. Often the passage of time reveals that earlier concerns did not come to pass. As a case in point, at the time of preparing the Initial Proposal, we were concerned that the region might be facing an El Niño year, which our forecasters tell us generally leads to lower precipitation in the Columbia Basin. Such a weather pattern tends to put downward pressure on BPA's revenues. If we had reflected the El Niño conditions in our risk models, the expectation of a 2014 CRAC would have been significantly higher than 12 percent. However, until we had better information about FY 2013 conditions, we did not consider it prudent to reflect these conditions in the Initial Proposal risk models. Preferring to keep the quantitative analysis untainted by personal opinion, we asked parties to address the question on a qualitative "what if" basis.

Now, as we approach mid-year estimates at the end of March and have three months of the marketing season behind us, BPA's FY 2013 financial condition is becoming more clear. It will be even clearer in early summer when the Final Proposal rates will be calculated. Given the choice of including what may turn out to be needless caution into the Initial Proposal rates, we chose to have the discussion with parties on a qualitative basis rather than a quantitative basis. As WPAG states, WPAG has historically supported use of the CRAC instead of PNRR given the choice of a possible rate increase versus a certain rate increase, but they do not have enough information at this time to make that call. Saleba *et al.,* BP-14-E-WG-01, at 5. Neither do we, but we believe that it was better to ask the question should the FY 2013 financial situation deteriorate.

We do note that in this circumstance, the choice is not a possible rate increase versus a certain rate increase; rather, the choice is how to implement a certain rate increase, whether recovering a shortfall over one year versus two years. Although rate increases are not a pleasant subject to discuss, there are downside ramifications to either approach; thus, discussions are superior to reliance on only one approach.

Section 5: Contracted For/Committed To (CF/CT) Load

Q. *ICNU contends that CF/CT loads that are "unused" should be charged cost-based rates under section 7(b)(1) of the Northwest Power Act, based on the lowest-cost resources used to serve the general requirements of public utility customers of BPA. Deen, BP-14-E-IN-01, at 15. ICNU states that CF/CT loads should be served at a Tier 1 rate or at a minimum a melded rate. Id. Is this the first time ICNU has raised this issue?*

A. No. Although a slightly modified argument, ICNU is essentially recycling a contention it initially made in the TRM-12 rate proceeding that was rejected by the Administrator in the Tiered Rate Methodology (TRM) Record of Decision. TRM-12-A-01, section 2.0. ICNU renewed this same argument in the BP-12 rate proceeding, and again the Administrator rejected ICNU's arguments in the BP-12 Record of Decision. BP-12-A-02, section 2.1.1.

Q. *Please provide a background of CF/CT.*

A. The term "CF/CT" or "contracted for, or committed to" originates in section 3(13)(A) of the Northwest Power Act and the definition of the term New Large Single Load (NLSL). The Northwest Power Act defines an NLSL as follows:

> any load associated with a new facility, an existing facility, or an expansion of an existing facility –
> (A) which is not *contracted for, or committed to*, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and
> (B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve month period.

16 U.S.C. § 839a(13) (emphasis added).

The primary significance of a load that falls within the meaning of an NLSL pertains to rate treatment of BPA's service to that load. The Northwest Power Act expressly provides that NLSL is not part of the "general requirements," 16 U.S.C. § 839e(b)(4), *i.e.*, the firm power load of a public body, cooperative, or Federal agency that is served at BPA's Priority Firm Power (PF) rates established pursuant to section 7(b)(1) of the Northwest Power Act. If a public body, cooperative, or Federal agency has load that is determined to be a NLSL and wants to supply it with Federal power, BPA sells that amount of power to the utility at BPA's New Resource Firm Power (NR) rate. Power Rates Study, BP-14-E-BPA-01, at 130. The NR rate is different from BPA's section 7(b)(1) rate (the PF Public rate) and is developed in accordance with section 7(f) of the Northwest Power Act. The NR rate applies to BPA sales of firm power to investor-owned utilities under section 5(b) of the Northwest Power Act and for firm power purchased to serve any NLSL. Power Rate Schedules, BP-14-E-BPA-09, at 18. A load that is designated by BPA as a CF/CT load is excluded from the definition of an NLSL and therefore is excluded from service at the NR rate. Instead, such CF/CT load is treated as part of the utility's "general requirements" and is served at BPA's PF rates.

Since passage of the Northwest Power Act many utility customers have asked BPA to make CF/CT load determinations. Determination of CF/CT load includes the setting of a maximum or ceiling amount that can be served by the utility and purchased from BPA at the applicable PF rates. Since not all CF/CT loads have operated up to their ceiling amount, we assume ICNU's use of the word "unused" refers to that portion of the CF/CT load determination that has not materialized and is not consuming power. ICNU states that "CFCT loads are a special class of load recognized under the Northwest Power Act." Deen, BP-14-E-IN-01, at 15. ICNU overstates the meaning and importance of the clause "contracted for, or committed to" within the definition of NLSL. The language in the statute did not, as ICNU contends, create a special class of load. Rather, the benefit of a CF/CT load designation is to include it with the other load that makes up the utility customer's general requirements load that the utility may purchase from BPA at PF rates.

Q. You indicated that ICNU's argument is modified somewhat from the prior proceedings where ICNU raised this issue. How has ICNU modified its argument?

A. There are two modifications that are worth noting. In BP-14, ICNU has narrowed its argument to the question of whether, under the Northwest Power Act, CF/CT loads are entitled to service at Tier 1 rates or at a melded rate. Deen, BP-14-E-IN-01, at 15. In the prior proceedings, ICNU's arguments were significantly more detailed and varied, although in the end its arguments were all to support the contention that CF/CT loads are entitled to service by power the utility purchases from BPA at Tier 1 rates. These other arguments were addressed and rejected in both the TRM-12 and BP-12 Records of Decision. In addition to not re-raising a number of arguments, ICNU argues for the first time that CF/CT loads could be served "at a minimum" at a melded rate. *Id.*

Q. Does the addition of the melded rate option change Staff's assessment of ICNU's argument?

A. No. As previously noted, the fundamental flaw in ICNU's analysis remains the same; namely, that the CF/CT designation ensures only that such load is treated as part of the utility's "general requirements," and the utility may purchase such amounts from BPA at PF rates. The designation is not a guarantee for the utility to purchase from BPA at the Tier 1 rate or some other particular melded rate, only that the rates applied to the power sold to BPA's utility customer to meet CF/CT load will be BPA's PF rates.

Q. *ICNU states that "[f]or industries with unused CFCT load the determination can be extremely relevant as it can determine at what rate load growth is eligible to be served at by BPA." Deen, BP-14-E-IN-01, at 15. Does ICNU accurately describe the CF/CT designation?*

A. No. ICNU assumes that the "unused" CF/CT load determination belongs to the industrial consumer. While the CF/CT determination is specific to certain industrial consumers, the consumers do not hold the determination; the serving utility does. For instance, should an industry that has been determined to be CF/CT load of one preference customer physically change from one utility's service territory to the service territory of another BPA preference customer, the CF/CT load determination does not move with the load. We do not dispute the fact that the determination held by the utility may be important to the industrial consumer. The ability to avoid the NR rate for industrial load growth is of particular value. But the underlying assumption that the industries have "unused" CF/CT load is inconsistent with our understanding of the Northwest Power Act.

Q. *ICNU also assumes that the industrial consumer will automatically pay a Tier 2 rate for the additional CF/CT load. Deen, BP-14-E-IN-01, at 15. Do you agree?*

A. No. There are two fundamental flaws with this aspect of ICNU's argument. As previously noted, the CF/CT designation belongs to the utility, not the industrial consumer. As such, there is no guarantee that the utility will be purchasing power to serve the additional CF/CT load from BPA at the Tier 2 rate. The determination of whether BPA will sell the utility power at Tier 1 or Tier 2 rates depends entirely upon whether the utility has "headroom" under its Rate Period High Water Mark (RHWM) to "absorb" the additional load without needing to take service at a Tier 2 rate. It is possible that the serving utility could have sufficient headroom such that it would purchase the power from BPA at Tier 1 rates to serve the additional CF/CT load.

Additionally, ICNU assumes that the rate for BPA power used to meet the CF/CT load will be paid by the industrial consumer. As previously noted, the serving utility, not the industrial consumer, will pay the rates charged by BPA for the additional load. Industries that have CF/CT load have no contractual relationship with BPA and are not served by BPA at any rate. To the contrary, CF/CT loads are part of the general requirements of BPA's customers. The industrial consumer will pay the serving utility for its power service at the retail rate adopted by the serving utility. This retail rate may or may not reflect rate levels or design features in BPA's rates. The question of the retail rates charged to industrial consumers by the serving utility is a matter outside the scope of this proceeding and is a matter in which BPA does not get involved.

Q. Is a melded PF rate an option for CF/CT loads?

A. No. First of all, as mentioned above, CF/CT loads do not purchase power directly from BPA. In addition, BPA established the Tiered Rate Methodology as a basis for designing its PF rate through 2028. Under tiering and in concert with BPA's Regional Dialogue Contract High Water Mark (CHWM) power sales contracts, utility load amounts eligible for service at Tier 1 rates have been established and are included in each utility's CHWM. A utility whose load grows to a point that exceeds its CHWM needs to make an election whether to supply such load with non-Federal power or have BPA supply Federal power at the applicable Tier 2 rate. The Tier 1 versus Tier 2 rate power supply issue for additional CF/CT load was considered and decided by the Administrator in July 2007.

Section 6: Updating Load Forecasts Used in the Final Proposal

Q. Is there anything noteworthy that has come to your attention regarding updating load forecasts that will be used in the Final Proposal?

A. Yes. As was noted in the load forecast testimony, Misley *et al.*, BP-14-E-BPA-12, at 5, Staff will be updating the load forecasts for the Final Proposal. It has come to our attention that the load forecast updates that will be forthcoming will include a noteworthy adjustment to customer peak load forecasts as compared to the Initial Proposal. While this adjustment falls within the ambit of the process of producing a new load forecast, we believe that the adjustment is of enough importance that parties to the rate proceeding would want to be aware that it is coming.

In the process of tracking revenues and costs, BPA management has become concerned that actual demand revenues have been significantly under-running forecasts during the first 15 months the BP-12 rates have been in effect. In FY 2012, demand revenues were about $20 million below forecast, and for the first three months of FY 2013, demand revenues are about $10 million below forecast. BPA management was concerned with these significant under-runs because, unlike energy under-runs that can be remarketed, demand under-runs have no alternate market to make up revenue under-runs.

As a result of management's questions, Staff is working to improve the process it uses in forecasting peak loads. Planned model changes cannot be implemented prior to the Final Proposal; however, for the final forecast a more-thorough review of peak load forecasts was completed to make them more accurate.

Q. What is the expected impact of these peak load forecast adjustments?

A. In looking at past forecasts, Staff forecasters believe that about one-half of the revenue under-run can be attributed to forecast error, and the other half is due to other factors, such as weather or the economy. They indicate that the additional review of peak load forecasts will reduce demand billing determinants, with the result of a reduction in the associated revenue of about $10 million per year.

The concern that leads us to inform parties is the effect of forecasting $10 million less demand revenue. The total amount of dollars BPA forecasts to recover through the PF rate does not change; nor does the total energy sales at the PF rate. However, demand revenues are a credit in the computation of the Non-Slice rate and, therefore, the forecast change translates into a $10 million annual increase in the Non-Slice Customer rate. We believe that this change from the Initial Proposal is significant enough to inform parties at this stage of the proceeding because the change might not be noticed or fully understood by our customers unless they dig into the details of the Final Proposal. Thus, in the interest of being more transparent, we are taking this opportunity to point out the impact of the forecast process adjustment.

Section 7: Oversupply Rate Issues

Q. Was the issue of Oversupply rates raised by any party?

A. Yes, two parties raised the issue of the timing of the Oversupply rate case (OS-14) versus the timing of the general rate case (BP-14) and potential impacts on future cost recovery.

Q. Please summarize the parties' testimony.

A. Joint Party 16 (JP16) is concerned that parties to the OS-14 rate case may propose that the costs of BPA's Oversupply Management Protocol (OMP) be allocated to the Network segment, and the timing of the two rate cases may preclude such a result. Baker *et al.,* BP-14-E-JP16-01, at 2-3. JP16 states that any such costs for FY 2014–2015 developed in the OS-14 rate case should be reflected in the Transmission Rate Study. *Id.* at 3. JP16 proposes that, if the OS-14 rate case is delayed (and indeed it has been delayed for one month), "BPA include in each Network rate an adjustment clause that would recover the forecasted amount for each year of the rate period so that the total charge would equal the charge that would have been levied had the forecasted amount been included in the calculation of the Network rates ….” *Id.* Such adjustment clause would be inoperative if BPA was able to include a forecast OMP cost in the Network segment revenue requirement. *Id.*

WPAG states that BPA should take action in the BP-14 case to provide for the recovery of OMP costs. Saleba *et al.*, BP-14-E-WG-01, at 59. WPAG proposes that BPA include in the BP-14 transmission rates a CRAC "that would allow BPA to collect OMP costs if it decides in the OS-14 case that inclusion in a revenue requirement, rather than a separate rate, is the best way to allocate and collect those costs." *Id.* at 60. The CRAC would not be needed if the decisions made in the OS-14 rate case regarding the collection of OMP costs are available in time to be reflected in the BP-14 case, if necessary. *Id.* at 61.

Q. Do you agree that an adjustment clause is necessary in the BP-14 rate case to allow for the recovery of OS-14 costs?

A. No. We do not share the procedural concerns of JP16 and WPAG. If, in the Oversupply rate case, BPA were to decide to include oversupply costs in the transmission rates (and/or power rates), it could be accomplished without the addition of an adjustment mechanism in BP-14 rates.

Similar to what JP16 and WPAG propose, BPA could propose in the OS-14 rate case adjustment clauses on the relevant power and/or transmission rates or propose separate rates that would be applicable to the relevant customers. BPA is not precluded from doing this simply because it did not make a similar proposal in the BP-14 rate case.

Q. What are the benefits of not incorporating OS-14 "placeholders" in the BP-14 rate proposal?

A. After issuing the BP-14 Record of Decision, BPA will file the BP-14 Final Proposal at the Federal Energy Regulatory Commission before the OS-14 case has concluded.

Including oversupply issues in both the BP-14 rate case and the OS-14 rate case would cause unnecessary confusion for all litigants and the Commission. In addition, injecting a highly contentious issue into the BP-14 rate case would put the BP-14 rate case at risk for an issue that is being decided in a separate forum. This is exactly the reason parties to the BP-14 and OS-14 rate cases recommended that we keep these cases in separate dockets.

Q. Are there any benefits to including Oversupply issues in the BP-14 rate case?

A. No. BPA does not believe there are any benefits to this approach. As a result, to avoid unnecessary confusion and putting the BP-14 rate case at risk, we do not believe implementing the JP16 and WPAG proposals is necessary.

Q. Does this conclude your testimony?

A. Yes.