10.0 WHOLESALE POWER RATE DESIGN

10.1 <u>Introduction</u>

BPA's 2002 rate proposal included changes in the calculation and design of wholesale power rates. A primary purpose of these changes is to accommodate the transition from the 1981 utility and DSI customer contracts to BPA's proposed Subscription contracts. Since 1981, the wholesale electric marketplace has experienced significant changes, including deregulation and the unbundling of products and services. Therefore, BPA proposed several new products and services that are intended to meet the demands of a more competitive electric utility marketplace and to better serve the needs of BPA's regional customers. In doing so, BPA also revised its rate design to reflect cost causation more accurately and provide price signals that will result in more efficient use of the FBS, which enables potential purchasers to compare BPA's products and services with those of alternative suppliers.

The primary changes in BPA's power rate design are as follows:

- BPA revised the six seasonal periods used in BPA's 1996 rates to monthly periods for energy and demand, section 10.2.

- BPA continued to use market forecasts in developing the monthly Demand Charge in order to send accurate price signals to customers, section 10.4.

- The Load Shaping Charge has been eliminated and replaced by the Load Variance Charge. The primary cost drivers of the Load Variance Charge are the customer's right to place load growth on BPA and energy consumption variations due to factors such as weather, section 10.5.

- The Unauthorized Increase Charges (UAI Charges) were modified to more accurately reflect the potential costs to BPA caused by customers exceeding their contractual entitlement to take power, section 10.6

- The Excess Factoring Charge was added to compensate BPA for providing factoring service that is outside the factoring benchmarks, section 10.7.

- A SUMY Charge has been adopted to compensate BPA for the estimated cost of serving a multiyear Block which steps up over the years, section 10.9.

- A C&R Discount was added to encourage and support the development of conservation projects and renewable resources in the region, section 10.13.

- The TAC was added; the TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period, section 10.15.

The Subscription core products and the design of the rates applicable to them were developed consistent with certain key BPA business principles, including equitable comparability among purchasers, the common tables of rates, and the concept of effective rate. BPA's Subscription core products were developed based on the principle that core products will be billed from a "common table of rates" to assure equitable comparability of payment among purchasers of different types of core products. There are common tables of rates for Demand, HLH and LLH energy, and Load Variance, where applicable. The common tables of rates are associated with tables of billing factors showing the billing determinants appropriate to the specific products--Demand, Demand Adjuster where applicable, HLH and LLH energy, Load Variance, and Unauthorized Increase and Excess Factoring.

10.2 Monthly and Diurnal Differentiation of Energy Charges

BPA is using the same basic approach to establish energy rates for the FY 2002-2006 rate period that was used in the 1996 rate case. Rates are shaped to a forecast of market-based marginal costs for the rate period and then adjusted so that the revenue requirement is neither overcollected, nor undercollected. Keep *et al*., WP-02-E-BPA-17, at 13. As in BPA's current rates, rates for FY 2002-2006 are diurnally differentiated. *Id.* The primary change is that BPA is setting monthly energy rates for the 2002-2006 rate period. *Id.* This is a change from the 1996 rate case, which had six seasons for HLH and LLH energy rates. *Id.* BPA proposed monthly energy rates for three reasons. First, spot market electricity prices in the Northwest are showing significant month-to-month variation. *Id.* For example, over the last two years the average month-to-month variation in electricity prices for firm onpeak power at Mid-C has exceeded 20 percent. *Id.* Second, BPA's Marginal Cost Analysis Study, WP-02-FS-BPA-04, shows substantial monthly differentiation in predicted energy rates for the FY 2002-2006 rate period. *Id.* Third, because of reduced flexibility in operating the hydrosystem, BPA is more frequently forced to purchase in the market to meet requirements load. *Id.* Therefore, to reduce BPA's exposure to market risks in meeting its contractual commitments to meet requirements load, it is appropriate for BPA to set monthly energy rates for the FY 2002-2006 rate period. *Id.* Because no party raised the issue of monthly and diurnal differentiation of energy charges on brief, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3, 51 Fed. Reg. 7611 (1986).

As stated in Keep *et al.*, WP-02-E-BPA-17, at 14, the 2002 HLH and LLH energy rates were established in a four-step procedure. First, BPA estimated its marginal costs for the FY 2002-2006 rate period. *See* Marginal Cost Analysis Study, WP-02-FS-BPA-04. BPA uses monthly energy rates from the Marginal Cost Analysis Study as inputs in the calculation of demand and load variance charges, and to shape the energy rates. Keep *et al.*, WP-02-E-BPA-17, at 14. Next, 2002-2006 demand and load variance revenues were calculated by multiplying the demand and load variance charges by estimated loads. *See* Loads and Resources Study, WP-02-FS-BPA-01. These revenues were subtracted from BPA's FY 2002-2006 revenue requirement. Keep *et al.*, WP-02-E-BPA-17, at 14. Finally, HLH and LLH energy rates were derived by adjusting the monthly and diurnal energy prices from the Marginal Cost Analysis Study to assure that only the revenue requirement is collected. *Id.* This is done because using forecasted market energy prices as rates would overcollect BPA's revenue requirement. *Id.* Monthly HLH and LLH energy rates from the Marginal Cost Analysis Study were reduced proportionately until estimated revenues from energy charges equaled the balance of BPA's revenue requirement. *Id.* Because no party raised the issue of how BPA established HLH and LLH energy prices on brief, this issue is withdrawn in accordance with the *Procedures.*

10.3 Rate Caps for Demand and Load Variance Charges

Issue

Whether BPA should remove or reduce caps on Demand and Load Variance Charges and adopt an alternative rate mitigation package to protect customers from excessive rate increases due to rate design changes.

Parties' Positions

The IOUs and PGE state that BPA ignored the rate mitigation proposal proffered by the HLFG. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61; PGE Brief, WP-02-B-GE-01, at 12. In their brief on exceptions, the IOUs incorporate by reference their initial brief. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01. NRU opposes the HLFG's alternative rate mitigation proposal. NRU Brief, WP-02-B-NI-02, at 6.

WPAG argues that the proposed increase for the PF rate Demand Charge is out of line with the level of increase being proposed for other rate components. WPAG Brief, WP-02-B-WA-01, at 4. WPAG states that an increase of more than 150 percent to the Demand Charge is not justified in a rate proceeding where the average PF rate will be unchanged. *Id.* PNGC argues that increases in the Demand Charges are dramatic and draconian and are seemingly inconsistent with BPA's assertion of maintaining rates at PF-96 levels. PNGC Brief, WP-02-B-PN-01, at 24.

BPA's Position

BPA proposed caps on the Demand and Load Variance Charges and is offering a power product under the FPS rate schedule to mitigate inordinate rate impacts on irrigation loads. Burns and Elizalde, WP-02-E-BPA-08, at 18. BPA rebutted recommendations made by the HLFG to remove the caps. Burns and Elizalde, WP-02-E-BPA-37, at 11. The price caps as proposed balance the competing goals of rate stability and product pricing to reflect cost. *Id*.

Evaluation of Positions

The IOUs and PGE argue that BPA's rebuttal "ignored" an alternative $30 million rate mitigation package that would be explicit rather than hidden in rate design. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61; PGE Brief, WP-02-B-GE-01, at 12. They make the supposition that none of BPA's workgroups looked at how BPA could achieve its rate design and rate impact mitigation goals to take into account BPA's Subscription policy goals. *Id*. They contend that this failure appears to be a function of BPA's "fragmented" rate development process. *Id*. They claim that adopting the HLFG recommendations will better effectuate both of the competing goals of sending appropriate market price signals and mitigating rate impacts. *Id*.

NRU supports BPA's proposed caps and argues that the HLFG mischaracterizes them as "mitigation." NRU Brief, WP-02-B-NI-02, at 7. NRU notes that the HLFG proposal starts by uncapping the Demand and Load Variance Charges and replacing both the caps and a $20 million mitigation proposal for selling surplus power to utilities with irrigation loads with an alternative mitigation program. *Id*. The alternative program would provide a total of $30 million for all impacted utilities over five years; would be front loaded; and would be phased out over the rate period. *Id*. NRU argues that the effects of this proposal would likely be exacerbated if the HLFG's proposals to model BPA rates after the volatility of the CalPX were adopted; it ignores the need for rate continuity and the significant adverse impacts that proposed changes in BPA's rate design will have on small full requirements utilities; it is inconsistent with the Subscription ROD that commits BPA to an irrigation mitigation program involving surplus sales over the entire rate period; and it is unsupported by any evidence other than the HLFG's heavy reliance on particular economic theories of ratemaking. *Id*.

The HLFG argued that both caps distort the market price signals and lead to economically inefficient solutions for society regarding electrical capacity usage. Koehler *et al*., WP-02-E-HL-01, at 9. In particular, the HLFG argued that the cap on the Load Variance Charge shifts approximately $20 million annually to energy charges. *Id*. BPA responded in rebuttal that it is necessary to keep the price caps as proposed. Burns and Elizalde, WP-02-E-BPA-37, at 11. This is based on the need to balance the competing goals of pricing products to reflect costs versus concern over the degree of rate impact in spreading the benefits of the FCRPS. *Id*. BPA is mindful that its rates, taken in total, must recover BPA's costs, taken in total. While BPA is moving toward a rate design for power products that appropriately sends price signals at the margin, BPA believes that there would be unreasonable rate impacts for some customers if BPA designed rates to fully reflect market signals. *Id*. BPA believes the 2002 power rates balance the competing goals of rate stability and product pricing to reflect cost. *Id*.

The HLFG's recommended mitigation alternative, Koehler *et al*., WP-02-E HL-01, at 29; includes aspects of BPA's rate proposal that are broader than the forms of rate mitigation BPA has offered. The HLFG included elements of BPA's initial proposal which the HLFG asserted "deliberately or inadvertently shift costs among customers and types of loads." *Id*. The HLFG identifies: (1) the cap on the Load Variance Charge; (2) two kinds of caps on the Demand Charge; (3) the new TBL obligation to incur incremental costs for non-Federal transmission service and the spreading of most GTA costs to all of BPA's power rates; (4) a summer/irrigation mitigation fund; (5) no-cost transmission management services for the smallest customers; (6) the LDD; and (7) the implementation of the rate collars in pre-Subscription contracts. *Id*. The HLFG alleged cost shifts of over $100 million annually without providing any supporting analysis or evidence to make a demonstration of any actual cost shifts. *Id*.

BPA agrees with the position taken by NRU that the HLFG's mitigation package is unsupported by any evidence. NRU Brief, WP-02-B-NI-02, at 7. The HLFG's proposal is further attenuated by inclusion of such a broad array of rate elements, which as a threshold matter, were either addressed by BPA to the extent a specific element was at issue in this rate case or were simply not claimed by the HLFG as causing cost shifts. Moreover, no evidence in the record supports the claim made by the parties that the rate elements identified by the HLFG would cause cost shifts of $100 million annually. For example, BPA rebutted the HLFG's argument regarding the caps on both the Demand and Load Variance Charges as described above. Burns and Elizalde, WP-02-E-BPA-37, at 11. Therefore, BPA rejects the IOUs' and PGE's recommendation that BPA adopt the HLFG's recommendations. BPA does not agree that the HLFG's recommendation will better effectuate BPA's policy goals. To the contrary, BPA believes it is more reasonable to rely on the forms of rate mitigation it has proposed to effectuate its policy goals than to adopt the unsupported recommendation made by the HLFG.

In contrast to the IOUs and PGE, WPAG and PNGC argue that the level of the cap for the Demand Charge should be lowered. WPAG claims the annual cap on the proposed Demand Charge is the minimum mitigation action needed to protect BPA's small and medium sized preference customers from substantial adverse impacts from the proposed Demand Charge increase. WPAG Brief, WP-02-B-WA-01, at 19. WPAG recommends that BPA adopt an annual Demand Charge of $1.80, which WPAG states will limit the increase of the Demand Charge to a little more than 100 percent. *Id*. at 20. Similarly, PNGC argues that the proposed cap to the Demand Charge is too great, and that the other forms of rate mitigation fail to adequately redress the impacts related to the Demand Charge. PNGC Brief, WP-02-B-PN-01, at 24-27. PNGC claims that the LDD is not rate mitigation; nor will $4 million in relief available to high irrigation load customers do anything for "typical" customers that have light irrigation loads that predominantly serve residential consumers. *Id*. at 25. PNGC, therefore, recommends that the Demand and Load Variance rates be limited to increasing no more than 30 percent over PF-96 rates or $1.13 for capacity on an annual average basis, and 0.42 mills/kWh for Load Variance Charges. *Id*.; Gonzales *et al*., WP-02-E-PN-04, at 3.

BPA again notes that these particular caps were selected based on a balancing of competing goals of wanting product pricing to reflect cost, and on the other hand, concern about the degree of rate impact as one consideration in spreading the benefits of the FCRPS. Burns and Elizalde, WP-02-E-BPA-08, at 18. BPA is aware that there would be impacts among the customers depending on their load shapes and usage. *Id.* By the changes in the Demand and Load Variance Charges, BPA is attempting to price its products such that they reflect costs to BPA. *Id.*

It is necessary to keep the price caps as proposed because of the need to balance the competing goals of pricing products to reflect costs versus concern over the degree of rate impact in spreading the benefits of the FCRPS. Burns and Elizalde, WP-02-E-BPA-37, at 11. Charging full market price would have unreasonable rate impacts for some customers. Burns and Elizalde, WP-02-E-BPA-08, at 18. While BPA is moving toward a rate design for power products that appropriately sends price signals at the margin, BPA believes that there would be unreasonable rate impacts for some customers if BPA designed rates to fully reflect market price signals. *Id.* The proposed caps provide rate mitigation in addition to other forms of mitigation BPA is offering. *Id.* Although PNGC claims the LDD is not a rate mitigation tool, the LDD when taken together with forms of rate mitigation certainly provides eligible customers rate relief. *See* Gustafson *et al*., WP-02-E-BPA-23. To at least partially mitigate rate impacts on seasonal loads, the 2002 rates continue the flexible PF rate while still maintaining the same amount of revenues for BPA. *Id.* The $4 million is, in the professional judgment of BPA's witnesses, an amount of money that will help to offset rate impacts for some customers and still allow BPA to meet its PF rate targets. *Id.*

Another issue PNGC raises in relation to the caps is the Demand Adjuster. PNGC notes that its recommendation, which was that the Demand Adjuster not be applied to Actual Partial Service-Simple (APS-S), went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC states that calculating the Demand Adjuster using Total Retail Load (TRL) and then applying it to the Demand Entitlement results in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC's witnesses concluded that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*.

BPA does not agree with PNGC's recommendation. In rebuttal BPA responded to a similar recommendation made by WPAG, which is equally applicable to PNGC's recommendation made in its brief. BPA notes that the product intent was to create demand billing parity for partial product purchasers in comparison to full service purchasers. Keep *et al*., WP-02-E-BPA-43, at 10. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA Generation System Peak (GSP) hour. *Id*. A customer with a flat resource leaves BPA with a "peakier" load than a customer that has a resource that follows part of its load shape. BPA's overall price signal to customers is intended to be that their mills/kWh effective rate should increase as the load factor placed on BPA decreases, *i.e*., becomes more peaky. *Id.* The Demand Adjuster was not intended to change that. PNGC's proposed change would make the price signal to a customer that uses a flat resource the same as a customer whose resource followed a portion of its load, as long as both customers are using the same energy amounts on BPA's system peak, even though the flat resource can leave BPA with the fluctuations of the customer's load to follow. This effective rate difference results in a price signal and also a proportionate distribution of the responsibility for paying a portion of BPA's revenue requirement. *Id*. In rebuttal, BPA pointed out that WPAG's proposed method would result in a lower Demand Charge as the GSP delivery amount decreased, whether or not the customer was helping to reduce the factoring service placed on BPA. *Id*. Under the WPAG method, a customer who supplied a flat diversification resource to its load would have chosen to place a higher load factor on BPA than a customer who supplied an equal MW amount on the GSP hour, but attempted to follow a portion of its own load placed on BPA. The recommendation made by WPAG's witnesses as to how to calculate the Demand Adjuster has the same end result for a flat diversification as the proposal made by PNGC as applied to the APS-S service. As BPA witnesses testified, this would weaken the price signal regarding choices that increase peaky load placed on BPA. *Id*. It also would counteract BPA's intention to distribute proportionate responsibility for payment of the revenue requirement to customers consistent with the obligations they place on BPA. *Id*.

Decision

BPA will cap Demand and Load Variance Charges at the levels set as part of its rate mitigation package to protect customers from excessive rate increases due to rate design changes.

10.4 Demand Charges

The Demand Charge is a $/kW per month charge that compensates BPA for three components of firm service: (1) the cost of firming bulk energy, including firm energy provided in flat amounts as under the Block product; (2) the service BPA calls "factoring," in which energy is distributed among hours to match a load shape; and (3) readiness to meet actual load under peaking conditions.

The method for computing the Demand Charges uses hourly values minus annual average values of market forecast prices. The method computes a delta which is the average of all the positive differences between hourly and annual average values. This delta reflects the cost of serving firm hourly loads. This annual average delta is converted to a five-year average and then shaped to AURORA average monthly onpeak prices, resulting in 12 monthly Demand Charges. More value is attributed to months where BPA faces higher prices that may result in higher costs to serve load. Less value is attributed to months where BPA faces lower prices that may result in lower costs to serve load. Since BPA did not propose hourly rates, the Demand Charge is needed to reflect firming costs and hourly price differentials. The Demand Charge plus energy rates tend to mimic the effect that hourly pricing would have had on the customer's effective mills/kWh rate. Keep *et al.*, WP-02-E-BPA-17, at 3-5. In order to mitigate the rate impact of the Demand Charge, BPA has capped it at a maximum of $2.50/kW per month, and at a maximum of $2.00/kW per month on an annual average basis. Keep *et al.*, WP-02-E-BPA-17, at 5; Burns and Elizalde, WP-02-E-BPA-08. Monthly demand rates are shown in the Wholesale Power Rate Schedules, Appendix 1, WP-02-A-02, section II.A. Demand Rate Table.

The source of data used for the market forecast is the Marginal Cost Analysis Study, WP-02-FS-BPA-04. This study uses the AURORA Model to estimate a market-clearing price forecast. The forecasted hourly prices are used to derive the Demand Charge. *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, section 2.3.1.2.1.

Issue 1

Whether the Demand Charge calculation method should be revised to use the annual energy prices across only the HLH period for each year of the rate period.

Parties' Positions

WPAG argues that the demand component of the PF rate does not accurately capture the value of firming, factoring, and peaking service provided under the PF rate. The Demand Charge should be calculated using the annual average energy prices across only the heavy load period for each year of the rate period. WPAG Brief, WP-02-B-WA-01, at 16-17.

BPA's Position

WPAG's assertion that these services are typically needed only in HLH is incorrect. Keep *et al*., WP-02-E-BPA-43, at 7. Including LLH prices in the annual average energy prices rather than just the HLH prices does not overstate the value of firming, factoring, and peaking. *Id*.

Evaluation of Positions

WPAG argues that during LLH periods BPA has more energy available than it can easily find loads to serve. WPAG Brief, WP-02-B-WA-01, at 17. The firming, factoring, and peaking services provided by the PF rate should be valued during the period that they are provided, and during the period that the market recognizes the value of such service, which is the heavy load period. *Id*. As a consequence, the calculation of the Demand Charge should not use the annual average energy prices across all hours for each year during the rate period. *Id*. WPAG contends that the proper threshold for the calculation of the demand component of the PF rate is the annual average energy prices across the heavy load period for each year of the rate period. *Id*.

WPAG argues that during LLH periods BPA has more energy available than it can easily find loads to serve. WPAG Brief, WP-02-B-WA-01, at 17. While WPAG is correct in its statement, WPAG fails to recognize that the Demand Charge is not billed on LLH. BPA's rate design sufficiently reflects a price signal regarding the HLH/LLH distribution of firming, factoring, and peaking costs, because the Subscription product billing factors for Demand are set in HLH only. Keep *et al*., WP-02-E-BPA-43, at 6. BPA testified that the demand method it chose necessitates using LLH pricing to capture the services of firming, factoring, and peaking by accounting for the differences in prices of all hourly energy prices across the year. *Id*. at 7. Demand cost is inherent in all hourly prices and not just in the HLH prices. There is some demand cost reflected in the difference between HLH and LLH prices. The cost of this demand component would not get captured in BPA's Demand Charge if LLH prices were not included in the annual average energy price. *Id*. at 7-8.

Contrary to WPAG's argument that the Demand Charge should be calculated using the annual average energy prices across only the heavy load period for each year of the rate period, BPA testified that firming and factoring are clearly used and needed in all hours where a variable generation resource must be managed and backed up to be delivered to a firm load. Keep *et al*., WP-02-E-BPA-43, at 7. BPA believes that including LLH prices in the annual average energy prices rather than just the HLH prices does not overstate the value of firming, factoring, and peaking. *Id*. Factoring FBS generation among LLH, in view of the differences between hourly LLH market prices, incurs cost. Open energy markets clearly display the hourly differentials among LLH, so firming and factoring for LLH obligations must reflect that hourly cost differential. *Id*. BPA testified further that viable commodity markets have not yet developed for unbundled stand-ready power products such as firming or factoring, as BPA uses those terms for Subscription products. *Id*. This is not because such products are not applicable outside of HLH or because they have no value. Rather, the reason for this is because such products tend to arise in connection with requirements service, such as provided by BPA, which is not usually represented among the array of commodity products that open markets tend to trade. *Id*.

WPAG also gives several reasons why BPA should adopt WPAG's proposed approach to calculating the Demand Charge. First, WPAG points out that BPA is striving for no rate increase to the average PF rate in this case. WPAG claims that if BPA retains its current PF rate Demand Charge approach, the Demand Charge will increase by over 150 percent. WPAG Brief, WP-02-B-WA-01, at 17. WPAG asserts that this is an unprecedented increase proposed at a time when there has been no material change to either the FBS resources supplying this product or to the market that is supposedly serving as a guide to BPA's rate design. *Id*. Second, WPAG contends that BPA has no compelling rationale to justify BPA's high Demand Charge. *Id*. at 18. WPAG asserts that it is not the case that BPA needs the increase in the Demand Charge to provide more revenue stability during the rate period. WPAG claims that because the preponderance of power products being offered by BPA to customers have a take-or-pay element, BPA will have a guaranteed revenue stream that is more predictable than that provided by a high Demand Charge. *Id*. WPAG states that as a result of the increase in the PF rate Demand Charge, BPA has had to substantially reduce the price it will charge for energy to avoid overcollecting its revenue requirement. *Id*. Consequently, BPA will be charging an energy rate that will be below the market rate for energy that is being predicted by the AURORA Model, and BPA's energy rates will be out of step with the market. *Id*. Finally, WPAG claims that the proposed Demand Charge will have an adverse impact on BPA's preference customers who have weather-sensitive loads, such as winter peaking and irrigation loads. WPAG argues that, in contrast, the methodology proposed by the WPAG direct testimony would result in an increase in the PF rate Demand Charge of about 24 percent, which is in line with the changes being made to other rate components. *Id*. WPAG claims that this one component most directly impacts BPA's small and medium sized preference customers.

BPA is not persuaded by the arguments made by WPAG. BPA's new Demand Charge definition and pricing for this rate period are more appropriate within the context of an unbundled, deregulated market. Keep *et al*., WP-02-E-BPA-17, at 6. In BPA's direct testimony, BPA described the changes in the Demand Charge computation from that used in the 1996 rate case. The MCA in the 1996 rate case computed values for capacity based on the costs of new resource additions. *Id*. at 5. Those values were used to derive the Demand Charge. This charge was averaged over all months, resulting in a single Demand Charge rate. *Id*. The Marginal Cost Analysis Study, WP-04-FS-BPA-04, for this rate case uses the AURORA Model, which does not compute capacity values. It computes only hourly energy prices, and therefore, because energy rates are derived using AURORA hourly prices, it is appropriate to derive a Demand Charge from AURORA. *Id*. This Demand Charge is shaped by month to reflect market prices. *Id*. The 1996 rate case defined demand as standing ready to serve instantaneous peakload, and the cost was derived from the capital costs of new resources. In that rate case, BPA charged as though it would acquire new generation resources to meet load. *Id*. In comparison to the computation in this rate case, unbundling as it has developed in the deregulated market has resulted in a more specific inclusion of expected market purchases for the supplier's portfolio of resources to serve its load. *Id*. at 6. Such purchases are made from markets that use hourly energy prices. Unbundling has also resulted in specific identification of risks such as price risk. *Id*. Due to the need to make market purchases as necessary, BPA undertakes price risk when it provides firming and stand-ready services to actual customer loads as part of firm requirements products. Loads that are not flat will cause peaks to occur in the market that will drive hourly prices higher during these peaks. *Id*.

BPA does not agree that WPAG's method for calculating the Demand Charge better reflects the market value of the service. BPA believes that WPAG's method undervalues demand. Keep *et al*., WP-02-E-BPA-43, at 8. BPA examined WPAG's proposed calculations and determined that they fail to capture the value for demand that is reflected by including the LLH in the average annual price, and thus would undercollect costs. *Id*. BPA's method is built on the premise that if a load were flat and BPA were to charge a single rate, then the annual average price would collect all costs. This works for a flat load, but not necessarily for a shaped load. *Id*. Therefore, to allocate costs equitably for shaped and flat loads, BPA's 2002 power rates include a monthly Demand Charge and monthly HLH and LLH energy charges. These monthly charges would result in the flat load paying the same charge as it would pay under a single annual average charge. *Id*. The shaped load would pay more or less than the average annual charge depending on whether the load was shaped into HLH or LLH or shaped into more or less costly months. *Id*.

Decision

The Demand Charge calculation method will not be revised.

Issue 2

Whether BPA should apply the Demand Adjuster to customers taking APS-S service.

Parties' Positions

PNGC notes that its recommendation that the Demand Adjuster not be applied to APS-S went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC claims that calculating the Demand Adjuster using TRL and then applying it to the Demand Entitlement would result in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC concluded that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*.

BPA's Position

BPA's Demand Adjuster methodology is specified in the Power Products Catalog, Appendix A, Product Billing Factors. Keep *et al*., WP-02-E-BPA-43, at 10. The product intent was to create demand billing parity for partial product purchasers and full service purchasers. *Id*. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA GSP hour. *Id*.

Evaluation of Positions

PNGC notes that its recommendation that the Demand Adjuster not be applied to APS-S went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC noted that an APS-S customer brings in a flat block at the bottom of its load. Gonzalez and Sher, WP-02-E-PN-04, at 7. PNGC contends that calculating the Demand Adjuster using TRL and then applying it to the Demand Entitlement results in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC recommended that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*. Further, BPA should amend its schedules to remove application of the Demand Adjuster from APS-S. *Id*.

BPA does not agree with the recommendation in PNGC's brief. In rebuttal testimony BPA responded to a similar recommendation made by the WPAG. BPA notes that the intent for the product was to create demand billing parity for partial product purchasers and full service purchasers. Keep *et al*., WP-02-E-BPA-43, at 10. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA GSP hour. *Id*. As PNGC correctly points out, an APS-S customer will use a flat resource. However, a customer with a flat resource places BPA in a position of needing to serve a "peakier" load, as opposed to a customer that has a resource that follows some or most of its load shape. BPA's overall price signal to customers is intended to be that the customer's mills/kWh effective rate should increase as the load factor placed on BPA decreases, *i.e*., becomes more peaky. The Demand Adjuster was not intended to change that. PNGC's proposed change would make the price signal to a customer that uses a flat resource the same as a customer whose resource follows a portion of its load, as long as both customers are using the same energy amounts on BPA's GSP, even though the customer using the flat resource puts BPA in the position of serving the fluctuations, *i.e*., peaks, in its load. This runs counter to BPA's intended price signal. The effective rate difference results in a price signal and also a proportionate distribution of the responsibility for paying a portion of BPA's revenue requirement. *Id*. In rebuttal, BPA pointed out that WPAG's proposed method would result in a lower Demand Charge as the GSP delivery amount decreased, whether or not the customer was helping to reduce the factoring service placed on BPA. *Id*. Under the WPAG method, a customer who supplied a flat diversification resource to its load would have chosen to place a peakier load on BPA than a customer who supplied an equal MW amount on the GSP hour but attempted to follow a portion of its own load placed on BPA. The recommendation made by PNGC as to how to calculate the Demand Adjuster methodology has an end result similar to that of WPAG's proposal as applied to the APS-S service. BPA witnesses testified that this would weaken the price signal regarding choices that increase peaky load placed on BPA. *Id*. It also would counteract BPA's intention to distribute proportionate responsibility for payment of the revenue requirement to customers consistent with the obligations they place on BPA. *Id*.

Decision

BPA will apply the Demand Adjuster to customers taking APS-S service.

10.5 Load Variance Charge

Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Variability in monthly energy consumption may be caused by weather, economic business cycles, load growth, or load loss. It does not include the variance in load caused by the customer's actions to annex new load, or variance in load due to retail access, or variance caused by service to New Large Single Loads (NLSL). Such loads will receive Load Variance coverage once they are served by BPA under the applicable firm power rate. Keep *et al.*, WP-02-E-BPA-17, at 7. Details of the product and rate case considerations and issues are discussed below.

The Load Variance service shifts the planning risk to BPA for all variations between actual and forecasted retail loads. With Load Variance, BPA will deliver additional power at the PF or NR rate to meet variations in retail load above forecast and will reduce PF or NR deliveries for variations in retail load below forecast. The Load Variance product is available to Full and Actual Partial utility customers under 2002 Subscription contracts. The Load Variance Charge under the Full and Actual Partial Service products entitles customers' billing factors to follow actual consumption. This differs from Block products, where the amounts to be paid are fixed. Keep *et al.*, WP-02-E-BPA-17, at 7.

The Load Variance Charge is applied to TRL (as defined in the General Rate Schedule Provisions, GRSPs), because under the Subscription core products, BPA's service applies to the entire TRL even if the customer dedicates some resource amounts to service its load. If the Load Variance Charge were applied only to net load, customers would pay unequally for the same service. Keep *et al.*, WP-02-E-BPA-17, at 13.

BPA proposed to set the Load Variance Charge based on the market costs of avoiding the price risk of serving variations in load. Keep *et al.*, WP-02-E-BPA-49, at 2-3. BPA assumed that it could buy call options in the financial market to guarantee purchase prices to serve load in excess of forecast, and that it could buy put options to guarantee sale prices in the market to ensure no change in expected revenue when loads do not materialize, *i.e.*, loads below forecast. *Id*.

The Load Variance Charge was calculated by computing load growth amounts from the five-year monthly forecast of TRL as reflected in the NWPPC's forecast of public and Federal agencies' TRL. Loads and Resources Study, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A. The cost to serve load growth was calculated using call option pricing. Load variation was estimated to have a 3.7 percent average upside variation and a 0.4 percent average downside variation. These variations were determined by comparing regional combined load forecasts for generating and non-generating public utilities to subsequent actual loads for the period October 1990, through September 1995. The cost to serve load variation was calculated using call option pricing for upside variation and put option pricing for downside variation. A detailed explanation of the derivation of the rate can be found in the Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 18-20.

This Load Variance option pricing method resulted in a cost of 1.19 mills/kWh on forecasted TRL. Keep *et al.*, WP-02-E-BPA-17, at 17. To mitigate the rate impact relative to PF-96, the cost of 1.19 mills/kWh was capped at 0.80 mills/kWh. *Id*. A description of the reasons for capping the rate is described in Burns and Elizalde, WP-02-E-BPA-08.

Issue 1

Whether the Load Variance Charge should be revised because it overstates the value of service BPA provides.

Parties' Positions

WPAG and SUB agree that the proposed Load Variance Charge should be capped but, they argue, it is substantially overstated and should be revised in order to reflect the value of the service BPA provides. WPAG Brief, WP-02-B-WA-01, at 20; SUB Brief, WP-02-B-SP-01, at 6.

SUB also argues that the Load Variance charge should include a component priced at the unit cost of FBS resources. *Id*. SUB reiterates its arguments and claims its positions on Load Variance were ignored in the Draft ROD. SUB Ex. Brief, WP-02-R-SP-01, at 7.

BPA's Position

BPA argued that the Load Variance charge reflects the value of the service, that it is not overstated, and that it should not be revised. Keep *et al*., WP-02-E-BPA-43, at 17-19. BPA is not allocating or functionalizing specific costs to any individual product or billing factor. Keep *et al*., WP-02-E-BPA-43, at 12. BPA has used some proxy pricing approaches to develop "price-signal" rates for certain billing factors such as Load Variance. *Id*.

Evaluation of Positions

WPAG argues that the proposed Load Variance Charge is substantially overstated and should be revised in order to properly reflect the value of the BPA service. WPAG Brief, WP-02-B-WA-01, at 20. WPAG suggests that BPA make the following revisions: eliminate the risk costs that are already being collected in PNRR; remove the costs of expected growth already included in the PF and NR rates; use a bandwidth for the deviations above and below the forecast of +/- 2.05 percent; and credit the revenue forecast to be collected from the Load Variance Charge to only the PF and NR rates. *Id.*

WPAG's first suggested revision is to eliminate the risk of costs that are already being collected in the PNRR. WPAG contends that the costs of weather and load included in the calculation of the Load Variance Charge are being double-counted, because they are also included as potential cost exposure in the amount of PNRR BPA needs to collect. WPAG Brief, WP-02-B-WA-01, at 20. BPA stated in testimony that PNRR includes a cost for risk associated with the published rate for the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 17. The risk is based on the possibility that any and all Subscription sales, including the Load Variance service, may not recover BPA's revenue requirement; therefore, no customers will be double-charged by applying the Load Variance Charge. *Id*. at 18. BPA's forecast of revenue from Load Variance Charges is netted out of the total revenue requirement prior to computing the PF and NR energy rates; therefore, no customers are double-charged for PNRR. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 52, lines 1 and 2.

WPAG's second suggested revision is to remove costs of weather variations and expected load growth from the Load Variance Charge because they are already included in PF and NR rates. WPAG Brief, WP-02-B-WA-01, at 20-21. WPAG argues that customers are being double-charged for the costs of load growth. *Id*. WPAG claims that including forecast load growth in the calculation of the Load Variance Charge, when such costs have already been included in the PF rate, amounts to double-counting the costs of this load growth and unnecessarily inflates the level of the Load Variance Charge. *Id*. WPAG contends that the Load Variance Charge should be calculated on the basis of unforeseen load variations, and not include load growth that is forecast. *Id*. at 21.

Removing weather variations and load growth costs from the Load Variance Charge would cause an underrecovery of revenue requirement or an increase in other PF rates. BPA should not remove the cost components related to weather and load growth variations from the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 17. BPA testified that because it is not allocating costs directly to specific billing determinants, BPA estimates what it might cost if BPA decided to separately cover monthly energy uncertainty with an option. *Id*. at 17. BPA then uses that estimate to come up with a price-signal rate for load variance. Keep *et al*., WP-02-E-BPA-43, at 17. The estimated revenues from the Load Variance Charge reduce the revenue requirement that the PF energy rates must recover. The costs associated with load variance are first calculated, then capped, and then removed from the revenue requirement. Keep *et al*., WP-02-E-BPA-43, at 19. BPA testified further that its forecast does not show that it will have surplus firm power available on an annual basis to meet load growth during the rate period. Charging for load growth in the Load Variance Charge provides BPA cost coverage for the cost associated with increasing the FBS to serve customers' load growth at PF rates. *Id*. at 18.

WPAG's third suggested revision is for BPA to use a bandwidth for deviations above and below the forecast of +/- 2.05 percent. WPAG Brief, WP-02-B-WA-01, at 21. WPAG contends that without such a bandwidth, BPA's calculation would be statistically unsound. *Id*. WPAG states that it should be assumed that unforeseen variations from forecast will be random, and such variations will occur above forecast as often as they will occur below the forecast. *Id*. WPAG's testimony on the Load Variance Charge suggested that BPA use the forecast and actual loads for the combined group of utilities to calculate the monthly load deviations, and then take the averages of the positive and negative differentials over the five-year test period. Cross *et al*., WP-02-E-WA-01, at 56. Using this method results in a 3.7 percent positive and 0.4 percent negative deviation from the 1991 forecast. *Id*. WPAG's witness concluded that given an equal spread of probable loads, the simple average of 2.05 percent ((3.7 + 0.2)/2) should be used for the positive and negative deviations. *Id*. at 57. SUB agrees with WPAG's argument. SUB Brief, WP-02-B-SP-01, at 6.

In rebuttal, upon examination of the data described in WPAG's testimony, BPA determined that the distribution of actual load around the forecast is approximately equal in magnitude when looking at the maximum deviation above and below the forecast. Keep *et al*., WP-02-E-BPA-43, at 19. However, more occurrences are observed of loads above forecast than below forecast. *Id*. Therefore, the average error above the forecast is greater than the average error below the forecast. BPA's analysis results in a 3.8 percent positive and a 0.7 percent negative deviation from the forecast. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 2. BPA concludes that a uniform bandwidth for deviations above and below the forecast is not appropriate.

WPAG's final suggested revision is for BPA to credit the revenue forecast from the Load Variance Charge to only the PF and NR rates. WPAG Brief, WP-02-B-WA-01, at 21. WPAG argues that crediting the Load Variance revenues to all firm power rates provides a subsidy to purchasers under the RL and IP rates by allowing them to share the revenues from a charge that they are not required to pay, creating an inequitable cost shift. *Id*.

BPA does not agree with WPAG's contention that BPA will provide a subsidy to purchasers under the RL and IP rates by crediting revenues to all firm power rates, including the RL and IP rates, which are not subject to the Load Variance Charge. BPA has testified that it is not allocating costs directly to specific billing determinants. Keep *et al*., WP-02-E-BPA-43, at 17. Instead, BPA estimates what it might cost if it decided to separately cover monthly energy uncertainty with an option. *Id.* This estimate is used to come up with a price-signal rate for Load Variance. *Id*. BPA is not necessarily going to buy such options to cover a specific subset of BPA's loads. *Id*. BPA will actually be covering total Subscription inventory and load uncertainty simultaneously through a portfolio of long- and short-range approaches. *Id*. Moreover, BPA estimated the cost of the Load Variance service and forecasted that the revenues from the Load Variance product will exactly equal those costs; therefore, there is no subsidy to a class of customer that does not purchase the Load Variance service.

SUB's brief on exceptions notes that the Draft ROD ignored SUB's positions on Load Variance in its initial brief and encourages BPA to address SUB's comments. SUB Ex. Brief, WP-02-B-SP-01, at 7. SUB argues that because BPA "can meet a portion of Load Variance service to Preference Customers with the flexibility in the FBS, the Load Variance charge should include a component priced at the unit cost of FBS resources." SUB Brief, WP-02-B-SP-01, at 6. BPA understands SUB's proposition to mean that SUB believes BPA's system has flexibility to operate and provide additional energy or resell unused energy in periods in which BPA is called upon to provide customers with Load Variance service. However, the Load Variance Charge approximates the amount of incremental or marginal cost risk BPA must bear in providing Load Variance service. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 18. The risk is standing ready to serve an unknown quantity at an unknown cost, but at a fixed price. *Id*. When loads are above or below the forecast, BPA could purchase or sell in the market at an unknown price. *Id*. BPA has reviewed SUB's suggestion, but as stated in testimony, the Load Variance charge was developed using a proxy pricing approach that results in a "price-signal rate." Keep *et al*., WP-02-E-BPA-43, at 12. That should not be confused with saying that those are BPA's plans of service or that BPA will actually incur costs in such an earmarked way. *Id*. BPA will actually be planning and operating to match generation plus other inventory to all load BPA is obligated to serve under existing and Subscription contracts. *Id*.

Finally, SUB agrees with BPA's decision to cap the Load Variance charge. In its initial brief, SUB quotes the following from the Energy and Water Development Act of 1993:

> . . . none of the funds made available under this Act, subsequent Energy and Water Development Appropriations or any other law hereafter shall be used for the purposes of conducting any studies relating or leading to the possibility of changing from the currently required "at cost" to a "market rate" or any other noncost-based method for the pricing of hydroelectric power by the six Federal public power authorities, or other agencies or authorities of the Federal Government, except as may [sic] specifically authorized by Act of Congress hereafter enacted.

SUB Brief, WP-02-B-SP-01, at 6, quoting 42 USC 7152. SUB argues in its brief on exceptions that BPA (in complying with 42 U.S.C. 7152) cannot conduct studies which lead to the charging of power at market rates, particularly for a product which applied for general service for core subscription products. SUB Ex. Brief, WP-02-R-SP-01, at 7. SUB does not state how the above statute relates to this current section 7(i) proceeding. Nor does SUB allege one way or the other regarding the use of appropriated funds to conduct any studies whatsoever. Therefore, BPA does not find this particular statutory reference relevant to setting cost-based rates in this proceeding.

Decision

BPA has determined that the methodology used to calculate the Load Variance Charge is appropriate and does not overstate the value of service BPA provides.

Issue 2

Whether the Load Variance billing factor uses the wrong baseline to calculate Load Variance Charges.

Parties' Positions

PGP argues that a billing factor based on TRL is improper ratemaking, because it bases a charge for a variable load on a fixed retail load. PGP Brief, WP-02-B-PG-01, at 6-8; PGP Ex. Brief, WP-02-R-PG-01, at 3-6. PGP argues that the Load Variance service should instead be based on factors that account for the variable nature of the proposed service. *Id*. PGP and the DSIs argue that customers with stable or constant loads will absorb costs of those customers with fluctuating loads. *Id*.; DSI Brief, WP-02-B-DS-01, at 80. Cowlitz joins PGP's exceptions and independently preserves its exception that the proposed billing factor is not based on the actual variable loads that create cost of service for BPA. Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-6.

BPA's Position

BPA does charge the Load Variance charge to those loads that fluctuate, but based on an average across all public generating and non-generating loads. Keep *et al*., WP-02-E-BPA-43, at 15. This is consistent with the overall rate design of billing on a common table of rates. *Id*. A customer whose load does not vary has the option of purchasing a Block product that does not incur the Load Variance Charge. If a customer's load does vary, it could still purchase a Block product and cover load variation from the market or through a negotiated FPS product from BPA. *Id*.

Evaluation of Positions

PGP argues that TRL is a fixed load. PGP contends that BPA's proposal relies on a faulty comparative analysis of the proposed Load Variance Charge. PGP Brief, WP-02-B-PG-01, at 6. BPA's method uses a fixed base to measure a fluctuating variable. *Id*. PGP claims that BPA customers with relatively flat loads, or even customers with no load, will bear an unequal proportion of costs for the Load Variance service compared to those customers that actually have load variations. *Id*. at 6-7. TRL is not a fixed load. Keep *et al*., WP-02-E-BPA-17, at 7. Load Variance applies to the variability in monthly energy consumption within the BPA customer's system. *Id*. Inherent in the TRL is the variability caused by weather, economic business cycles, load growth, and load loss. *Id.* BPA stands ready to serve this variability under the Full and Actual Partial service products. *Id*. The service entitles customers' billing factors to follow actual consumption.

PGP and Cowlitz argue BPA does not support with any evidence or testimony in the record when and how often weather (or other unnamed factors for that matter) proportionally affect the proposed Load Variance billing. PGP Ex. Brief, WP-02-R-PG-01, at 5; Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-3. They contend, without any support, that it is "indisputable that the loads of certain industrial customers are largely unaffected by weather fluctuations." *Id*. They conclude, "Bonneville wrongly assumes that weather affects the TRL of all customers equally." *Id*.

PGP and Cowlitz focus on this narrow example of load variation to argue that Load Variance should not be based on TRL, but rather on the actual variance for which it seeks recovery of its costs. PGP Ex. Brief, WP-02-R-PG-01, at 5; Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-3. Their argument is not persuasive. BPA notes that variability in monthly energy consumption may be caused by factors other than weather, such as economic business cycles, load growth, or load loss. Keep *et al*., WP-02-E-BPA-17, at 7. It is not isolated to any one specific event occurring in the month. BPA does charge those loads that fluctuate, but based on an average across all public generating and non-generating loads. Keep *et al*., WP-02-E-BPA-43, at 15. This is consistent with the overall rate design of billing on a common table of rates. *Id*. A customer whose load does not vary has the option of purchasing a Block product that does not incur the Load Variance Charge. If a customer's load does vary, it could still purchase a Block product and cover load variation from the market or through a negotiated FPS product from BPA. *Id*.

BPA's Load Variance Charge is based on historical forecast data, actual resulting load data, and a load growth forecast. Keep *et al*., WP-02-E-BPA-17, at 6. BPA testified that Load Variance service costs are a function of the size of the potential change in load, and the size of potential changes in load is a function of the absolute size of the total load. Keep *et al*., WP-02-E-BPA-43, at 14. Further, the Load Variance Charge was based on observed deviations from forecast. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, section 4.1. The cost of those deviations is spread over TRL. Keep *et al*., WP-02-E-BPA-43, at 14. Therefore, TRL is an appropriate billing factor, because the potential changes in load are a function of TRL. *Id.*

<u>Decision</u>

The billing factor for Load Variance has the appropriate baseline to calculate the customer's TRL.

<u>Issue 3</u>

Whether the TRL billing factor should exclude Block purchases.

Parties' Positions

PGP argues that because BPA's proposed TRL billing factor is an inaccurate method to bill variable loads, which creates a cross-subsidy requiring customers with relatively stable or constant loads to absorb costs of customers with fluctuating loads, BPA should instead focus on actual or contracted monthly load variances to calculate its Load Variance billing factor. PGP Brief, WP-02-B-PG-01, at 7. An example, given by the PGP, is to exclude Block power purchases from the TRL billing factor, because a Block power sale does not vary. *Id*. at 8. PGP and Cowlitz maintain that block power purchases should be excluded from the TRL when calculating Load Variance charges. PGP Ex. Brief, WP-02-R-PG-01, at 6-7; Cowlitz Ex. Brief, WP-02-R-CO-01, at 4-5. Both parties contend that BPA's rationale for including block power purchases in the calculation is not factually grounded, nor supported by any evidence in the record. *Id*.

BPA's Position

TRL is the appropriate billing factor to calculate the Load Variance charge. Keep *et al*., WP-02-E-BPA-43, at 14. TRL should not exclude Block purchases. While the amount of power in a Block purchase will not vary, the underlying load is not affected and will still vary proportionately due to weather, economy, and load growth. Keep *et al*., WP-02-E-BPA-43, at 16.

Evaluation of Positions

PGP argues for a remedy to escape what it contends is a cross-subsidy provided by customers with relatively flat or constant loads to customers with fluctuating loads. PGP Brief, WP-02-B-PG-01, at 7. PGP and Cowlitz contend that the record is devoid of support for BPA's conclusion that "[t]he variation in TRL includes any variation of the underlying load." PGP Ex. Brief, WP-02-R-PG-01, at 6; Cowlitz Ex. Brief, WP-02-R-CO-01, at 4. PGP suggests a remedy, which is to exclude from the TRL any Block power purchases. *Id*.

BPA does not agree with the PGP and Cowlitz position. The record supports BPA's conclusion. PGP and Cowlitz note that "loads that cannot vary, due to contractual obligations, are by definition excluded from causing any variation in the load placed on Bonneville." PGP Ex. Brief, WP-02-R-PG-01, at 7; Cowlitz Ex. Brief, WP-02-R-CO-01, at 5. BPA's witnesses have discussed the relationship of this type of load and the conditions that apply to it. *See* Keep *et al*., WP-02-E-BPA-43, at 11. An example of a load qualifying for an adjustment to TRL for purposes of the Load Variance Charge billing determinant would be one that BPA has no obligation to serve. Keep *et al*., WP-02-E-BPA-43, at 11. Such load must be separately hourly metered, its power supply must be hourly scheduled, and schedules and metered data must be provided to BPA. *Id*. Also, meeting the load's variation must be an obligation of a party other than BPA. *Id*. While this type of load may be exempt from the Load Variance Charge, it may be subject to other charges such as energy imbalance. *Id*. The customer-specific power sales contract will determine adjustments to TRL. *Id*. In comparison, for customers that do not have such exempt load and place BPA in the position of standing ready to meet the fluctuations in the customer's load, BPA has stated that TRL is an appropriate billing factor to calculate the Load

Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 14. While BPA may agree with PGP that the Block power purchase does not vary, it does not prevent the underlying load from varying. *Id.* at 16. The variation in the TRL includes any variation of that underlying load. For example, Block service combined with a load following service such as Actual Partial service does not shift the load variation risk to the BPA customer. *Id*. The Actual Partial service would still cover the total fluctuations that occur in the TRL above Block service. *Id*. Therefore, BPA believes that the correct billing determinant with this combination is TRL. *Id*.

Decision

The TRL billing factor will not exclude Block purchases.

Issue 4

Whether BPA should negotiate a limited Load Variance service for those customers anticipating such a need.

Parties' Positions

PGP argues that BPA should negotiate a limited Load Variance service for those customers anticipating such a need, which would replace the "Total Retail Load Less Block" billing factor. PGP Brief, WP-02-B-PG-01, at 7.

BPA's Position

BPA has offered to negotiate various products under the FPS-96 rate schedule and could negotiate a service similar to Load Variance. Keep *et al*., WP-02-E-BPA-43, at 16. The FPS product would have defined limits based on the customer's specific purchase amounts, whereas the Load Variance Charge billed against TRL has no limits. *Id*. A FPS product providing this type of Load Variance service could be billed in such a way so as to replace the TRL billing factor. *Id.*

Evaluation of Positions

The parties and BPA agree on this issue.

Decision

BPA will negotiate limited Load Variance service for customers.

Issue 5

Whether the Load Variance billing factor should be redesigned.

Parties' Positions

PGP argues that an alternative for customers interested in the Full Service or APS-S service would be to design a billing factor accounting for the difference in MWh between: (1) a customer's peak load multiplied by the number of billing hours in the month; and (2) the customer's average energy load for the month. PGP Brief, WP-02-B-PG-01, at 7. PGP contends that this billing factor would provide a reasonable proxy for the amount of load subject to fluctuation. *Id*.

BPA's Position

The Load Variance Charge, in part, covers the costs for the difference between expected loads versus actual loads. Keep *et al*., WP-02-E-BPA-43, at 16-17.

Evaluation of Positions

PGP provides no evidence as to how the difference between: (1) a customer's peak load multiplied by the number of billing hours in the month; and (2) the customer's average energy load for the month would reflect the uncertainty in load. PGP argued in its direct testimony for this change. Knitter *et al*., WP-02-E-PG-01, at 6. BPA noted that PGP provides no reasoning or evidence that its suggested billing factor is a measure of load variation. Keep *et al*., WP-02-E-BPA-43, at 16. It is not reasonable for BPA to redesign the billing factor as proposed by PGP without evidence to support the change. BPA's Load Variance Charge is based on historical data and a load growth forecast. *Id.* at 16. The Load Variance Charge, in part, covers the costs for the difference between expected loads versus actual loads. *Id*. The measure of peak versus average has nothing to do with expected loads versus actual loads. *Id*. at 17. The Load Variance Charge was based on observed deviations from forecast. *Id*. at 14. The cost of those deviations was spread over TRL. *Id*. Therefore, the correct billing determinant is TRL. *Id*.

Decision

BPA will not redesign the Load Variance billing factor.

Issue 6

Whether the Load Variance Charge should apply to all customers purchasing under the PF-02 rate unless specifically excluded.

Parties' Positions

The DSIs argue that, "[u]nless specifically excluded, a Load Variance Charge of 0.8 mills/kWh applies to all customers purchasing under the PF-02 Rate." DSI Brief, WP-02-B-DS-01, at 80. The charge will be applied to the customer's TRL, as defined in the GRSPs. *Id*. The DSIs state that "[t]he current definition of TRL in the GRSPs creates considerable ambiguity in that the rate schedules fail to define the circumstances in which certain loads would be exempt from the Charge." *Id*. "The DSIs propose that BPA amend the definition of Total Retail Loads [sic] so that the Charge does not apply to loads that impose no variance on BPA even if the load varies." *Id*. The DSIs state in their brief on exceptions that BPA has misstated the issue the DSIs raised in their direct testimony, Schoenbeck and Bliven, WP-02-E-DS-03, and at pages 79-80 in their initial brief regarding the Load Variance Charge. DSI Ex. Brief, WP-02-R-DS-01, at 11.

BPA's Position

Subscription core products that flex to meet actual consumption will have the Load Variance Charge applied to TRL. Block product entitlement and billing amounts are fixed in advance and are not altered to reflect after the fact measured power consumption. The Block energy does not change the monthly HLH or LLH contracted Block energy amounts. Keep *et al*., WP-02-E-BPA-17, at 9.

Evaluation of Positions

The DSIs recommend that BPA should either specify in each rate schedule (*e.g.*, PF-02, section IV.A. 1.3 of WP-02-E-BPA-07) that the Load Variance Charge shall be multiplied by the Purchaser's TRL "less any excluded load identified by contract," or alternatively, the definition of TRL (WP-02-E-BPA-07, at 125) should provide that, for purposes of computing the amount of the monthly Load Shaping Charges, certain loads identified by contract will be excluded. DSI Ex. Brief, WP-02-R-DS-01, at 11.

BPA and the DSIs agree that the Load Variance Charge applies to all customers purchasing under the PF-02 and NR-02 rates, unless the customer's contracted services specifically exclude Load Variance service. The GRSPs do not define TRL for the sole purpose of charging for Load Variance; therefore TRL should not be redefined. The definition of TRL does not address loads that are exempt from the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 11. Adjustments to TRL for applying the Load Variance Charge may be determined in the power sales contract and will exclude that portion of the TRL and its associated load variation that BPA is not obligated to serve. *Id*. An example of a load qualifying for an adjustment to TRL for purposes of the Load Variance Charge billing determinant would be one that BPA has no obligation to serve. *Id*. Such load must be separately hourly metered, its power supply must be hourly scheduled, schedules and metered data must be provided to BPA, and meeting the load's variation must be an obligation of a party other than BPA. *Id*. The customer-specific power sales contract will determine adjustments to TRL. *Id*. at 12. The DSIs agree with this criteria and BPA's intent to specify any load to be excluded from the Load Variance Charge by contract. DSI Ex. Brief, WP-02-R-DS-01, at 11. The DSIs note, however, that BPA's rate schedules and GRSPs do not provide for such exclusions. *Id*. BPA agrees with the DSIs that exemption to Load Variance should be identified within contracts and the rate schedules or GRSPs.

Decision

The Load Variance Charge applies to all customers purchasing under the PF-02 and NR-02 rates unless the customer's contracted services specifically exclude Load Variance service. The GRSPs contain language under the definition of TRL specifying the billing determinant for the Load Variance Charge for customers with exempt loads under their power sales contracts.

10.6 Unauthorized Increase Charges

BPA's UAI Charge methodology must be viewed in context with the relevant products and the BPA requirements service obligations under such products. BPA's core Subscription products are established in a forum outside the rate case. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 10-11. UAI Charges will apply when customers have contracted for Subscription power products but take amounts of power to which they are not entitled. Customers may be able to take amounts of power from BPA which are greater than they are entitled to if they fail to supply the amounts of other resources that they have committed to provide. BPA has a substantial economic and reliability interest in assuring that customers are unambiguously motivated in all timeframes to ensure the availability and delivery of their non-BPA resource amounts. UAI Charges are avoidable if customers arrange for appropriate reserve and firming products or services. Tr. 1213-15. These products and services can be self-supplied or obtained from suppliers in the market. Only if UAI Charges are clearly not an economic alternative to such reserve and firming arrangements can BPA be assured that FCRPS reliability will not be jeopardized. Therefore, UAI Charges apply to deliveries that exceed customers' contractual entitlements for demand and energy. BPA proposed that the charges for unauthorized increases in demand in any billing month be the greater of: (1) three times the applicable standard monthly demand charge; and (2) the sum of hourly California Independent System Operator (ISO) Spinning Reserve Capacity prices for all HLH in the month. Keep *et al*., WP-02-E-BPA-17, at 17. BPA also proposed that the UAI Charge for energy for each month be the greatest of: (1) 100 mills/kWh; (2) the maximum Dow Jones (DJ) Mid-C price; and (3) the maximum hourly ISO Supplemental Energy price. *Id.* at 17-18.

Issue 1

Whether BPA lacks the authority to impose a UAI Charge that is not reflective of BPA's cost.

Parties' Positions

PPC argues that the proposed UAI Charges are not cost based as required by BPA's statutes. PPC Brief, WP-02-B-PP-01, at 34; PPC Ex. Brief, WP-02-R-PP-01, at 7. In its brief on exceptions, PPC argues that "BPA arbitrarily, capriciously and without reason rejected PPC's recommendations." PPC Ex. Brief, WP-02-R-PP-01, at 8. OURCA argues that BPA lacks the authority to impose penalties without some basis tied to the underlying service and the associated costs that BPA may incur. OURCA asserts that the charges should be eliminated or revised. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

BPA's Position

BPA's UAI Charges have been developed as penalty rates, and not cost-based rates. Keep *et al*., WP-02-E-BPA-43, at 26. *See* 1993 ROD, WP-93-A-02, at 166-171. The argument that the UAI Charge should be cost-based is similar to arguments made by some parties in the 1993 and 1996 rate cases. *Id*. In both cases, the Administrator rejected those arguments. Keep *et al*., WP-02-E-BPA-43, at 26. *See* 1993 ROD, WP-93-A-02, at 166-171, and 1996 ROD, WP-96-A-02, at 321-322. Cost is only one consideration in setting the level of the UAI Charges.

Keep *et al*., WP-02-E-BPA-43, at 26; Tr. 1212-14. The intent of the UAI Charges is to deter customers from using BPA power in excess of their contractual entitlements and to impose a penalty when they do place an unauthorized increase on BPA's system. *Id*.

Evaluation of Positions

PPC argues that the foundation for BPA's proposed UAI Charges is suspect because it is not based on BPA's cost as required by statute. PPC Brief, WP-02-B-PP-01, at 37; PPC Ex. Brief, WP-02-R-PP-01, at 7. OURCA similarly contends that BPA lacks authority to impose these penalties without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

Since its inception in 1974, the UAI Charge has been developed to be a penalty and not a cost-based rate. *See* 1993 ROD, WP-93-A-02, at 169. FERC has recognized the Administrator's authority to impose a UAI Charge that is not cost-based. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,340 (1980). FERC approved BPA's UAI Charge of 100 mills/kWh in the 1970s, when power costs were less than 5 mills/kWh. 1993 ROD, WP-93-A-02, at 171. FERC predicated its approval on the fact that the UAI Charge was designed to modify customers' behavior. *Id*. FERC took notice of the fact that the charge was developed to assure that BPA's customers used their own resources first to meet their firm system load obligations. *Id*. As such, FERC noted that such a charge also ensures that the power BPA's customers marketed to others was truly excess resource capability. *Id*.

The minimum UAI Charge is necessary to ensure that there is always an incentive for customers to avoid placing unauthorized demand or energy increases on BPA's system. Keep *et al.*, WP-02-E-BPA-17, at 16-17. BPA's ability to plan its service obligations for the core Subscription products, as specified in the power sales contracts, and to control its costs depends on customers accurately specifying the obligations that BPA must serve. *Id*. at 17. Any occurrences of Unauthorized Increase undermine BPA's ability to plan these service obligations and control its costs. *Id*. The minimum charges, in conjunction with the potential for higher charges tied to market indexes, should encourage customers to select those products and services they need, and deter customers from using increases as an economic alternate source for those services. *Id*.

PPC, without any support, alleges that BPA lacks the statutory authority to base its power rates and charges on "lost opportunities." PPC Brief, WP-02-B-PP-01, at 37. PPC asserts that BPA's UAI Charges are intended to account for lost opportunities. *Id*. at 34. In direct testimony, BPA described that its costs are affected by market prices, and that market indexes provide a reasonable measure of its cost exposure, either as a representation of opportunity cost or purchase costs associated with serving an unauthorized increase. Keep *et al*., WP-02-E-BPA-17, at 16. BPA states that there may be times when unauthorized increases prevent or reduce BPA sales into the ISO markets, thus creating opportunity costs associated with serving the unauthorized increases. Keep *et al*., WP-02-E-BPA-43, at 25.

While BPA considers opportunity costs in the design of the UAI Charges, the opportunity cost concept by itself is not presented as an indispensable rationale for BPA's design. BPA presents several other reasons for its design. Tr. 1213-114. Nevertheless, opportunity cost pricing is a standard pricing method. Tr. 1205. BPA relied, in part, on opportunity cost pricing in the 1996 rate proceeding and in the development of the Load Variance Charges for the current rate proceeding. Tr. 1205. Also, in the 1985 rate case, BPA priced the first quartile of the DSI loads based on the opportunity cost of serving the first quartile with nonfirm energy. 1985 ROD, WP-85-A-02, at 150-155. It is appropriate for the UAI Charges to constitute a penalty, rather than to be tied to some cost basis. BPA adopts the principle of penalty-based UAI Charges. Additionally, the UAI Charges need to provide a sufficiently strong price signal to customers to plan and operate their systems in a fashion that avoids unauthorized increases on BPA's system.

BPA does not agree that it has acted in an arbitrary, capricious, or discriminatory manner as alleged by some parties. BPA's decisions are supported by the evidence in the record and are well reasoned and analyzed.

Decision

BPA has the authority to impose UAI Charges that are not strictly cost based.

Issue 2

Whether the use of California ISO price indexes is appropriate for the UAI Charges.

Parties' Positions

PPC opposes the use of California ISO Spinning Capacity Reserve and Supplemental Energy indexes for the UAI Charges for demand and energy, arguing that the ISO is demonstrably unreliable. PPC Brief, WP-02-B-PP-01, at 34-35; PPC Ex. Brief, WP-02-R-PP-01, at 7-8; Opatrny *et al*., WP-02-E-PP-02, at 20-22. PPC contends that the California ISO market indexes are flawed. PPC Brief, WP-02-B-PP-01, at 34-35; PPC Ex. Brief, WP-02-R-PP-01, at 7-8; Opatrny *et al*., WP-02-E-PP-02, at 20-22. PPC favors the use of DJ Mid-C price indexes in the determination of the UAI Charge for energy. PPC Brief, WP-02-B-PP-01, at 37-38; PPC Ex. Brief, WP-02-R-PP-01, at 8; Opatrny *et al*., WP-02-E-PP-02, at 22-23.

SUB also disagrees with BPA's proposed use of the California ISO charges for ancillary services as the basis for Unauthorized Charges. SUB Brief, WP-02-B-SP-01, at 7-8; SUB Ex. Brief, WP-02-R-SP-01, at 9-10. SUB notes its position is detailed in its direct testimony. SUB Brief, WP-02-B-SP-01, at 7; Nelson, WP-02-E-SP-01, at 4-8.

OURCA does not specifically address the use of California ISO indexes for the UAI Charges, but "adopts and joins" the positions stated in PPC's briefs with regard to the UAI Charges. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

PGP supports the use of market price indexes for the UAI Charges. Knitter and Peters, WP-02-E-PG-01, at 6. However, PGP does not express support for or opposition to the use of any specific market indexes.

BPA's Position

BPA proposed incorporating the California ISO Spinning Capacity Reserve price indexes for the UAI Charges for demand. Keep *et al*., WP-02-E-BPA-17, at 15-17. BPA also proposed the use of California ISO Supplemental Energy price indexes, in conjunction with DJ Mid-C price indexes, in its determination of UAI Charges for energy. Keep *et al.,* WP-02-E-BPA-17, at 14-18. BPA stated that omission of the California ISO indexes would, at times, create undue cost exposure to BPA and would not be a sufficient deterrent against such overruns. Keep *et al.*, WP-02-E-BPA-43, at 25-26, 30-31; Tr. 1212-14.

While BPA acknowledges current market imperfections at the ISO, Tr. 1206; Keep *et al*., WP-02-E-BPA-43, at 31; these imperfections do not undermine the California market's relevance to BPA's cost exposure. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1212. The specific forces that drive ISO price levels during any specific period are less relevant than the price levels themselves; it is the price levels, irrespective of their underlying determinants, that define BPA's cost exposure to unauthorized increases in demand. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1206-07. The inclusion of California ISO price indexes in BPA's UAI Charge methodology is appropriate because, although the California ISO is not based in the Northwest, those price indexes are an indicator of BPA's cost exposure because of the very nature of the west coast markets. *Id*.; Keep *et al*., WP-02-E-BPA-43, at 33.

Evaluation of Positions

In direct testimony, BPA stated two reasons for including the ISO Supplemental Energy price indexes in its proposed design of the UAI Charge for energy. First, because ISO Supplemental Energy is traded on an hour-ahead basis, the ISO Supplemental Energy price index among all indexes most closely approximates the real-time circumstance that BPA faces when it must provide service to an unauthorized increase. Keep *et al*., WP-02-E-BPA-17, at 18. Second, there is more certainty around the availability of this index than the CalPX price indexes. *Id.* BPA proposed inclusion of the ISO Spinning Capacity Reserve price index because, during certain high cost periods, the minimum UAI Charges for demand would understate the true costs of serving demand overruns and would not provide a sufficient deterrent against unauthorized increases in demand. Keep *et al*., WP-02-E-BPA-43, at 30-31. The incorporation of California ISO indexes for the demand and energy UAI Charges recognizes that BPA and the Northwest are part of the larger west coast markets, and the California markets are relevant to BPA's cost exposure. *Id.*; Tr. 1206-07, 1212.

PPC cites the California ISO's *Report on Redesign of California Real-Time Energy And Ancillary Services Markets* in asserting that there are market imperfections in the California ISO markets. Opatrny *et al.,* WP-02-E-PP-02, at 20. PPC also cites an additional California ISO Report, *Second Report on Market Issues in the California Power Exchange Energy Markets*, March 1999, which documents FERC's recognition of the need for price controls in the California ISO ancillary services markets. PPC Brief, WP-02-B-PP-01, at 34-35. PPC also documents FERC's November 1999 extension of price cap authority for an additional year for the California ISO markets to allow for market redesign. *Id.* at 35.

SUB argues that BPA should not use California ISO ancillary services market indexes to price unauthorized increases in demand, because of the California ISO's own acknowledgement that its ancillary markets are not behaving as expected, and because of market power issues associated with the California ISO ancillary services markets. Nelson, WP-02-E-SP-01, at 5. SUB asserts that "BPA is in error when it states that it is appropriate for BPA to use California ISO prices in its UAI charges for demand and energy." SUB Ex. Brief, WP-02-R-SP-01, at 10. SUB cites the California ISO's *Annual Report on Market Issues and Performance,* June 6, 1999. Nelson, WP-02-E-SP-01, at 4-5. SUB also cites this California ISO report in opposing the use of California ISO Supplemental Energy price indexes for UAI Charges for energy. *Id*. at 7. SUB points out that BPA's system load profile, with firm obligations that are winter peaking, differs from the summer peaking load profile of Southwest suppliers. SUB Brief, WP-02-B-SP-01, at 7-8. SUB argues that these regional differences in firm obligations place BPA in the "awkward position of basing UAI Charges on an ancillary services market in which it may be the only supplier." *Id*. SUB notes BPA's acknowledgement that "pricing at the ISO is highest in late summer and BPA's Loads and Resources Study shows BPA has a surplus of power during that time." SUB Ex. Brief, WP-02-R-SP-01, at 10. SUB contends that it is "inappropriate for BPA to implement charges that are subject to market power, especially in periods where BPA has a surplus of power and market prices are high." *Id.* SUB concludes that BPA should base its UAI Charges for demand similar to Southwestern Power Administration's (SWPA) penalty charges, at three times the fixed monthly demand charge. SUB Brief, WP-02-B-SP-01, at 7-8; Nelson, WP-02-E-SP-01, at 5-6. SUB cites the impacts of transmission congestion on the California ISO Supplemental Energy prices in asserting that BPA should use only the DJ Mid-C indexes for its UAI Charges for energy. *Id.* at 7-8.

PPC and SUB both cite to reports that purportedly demonstrate the imperfections of the California ISO. These reports have no evidentiary weight and have not been entered into evidence by any party in this section 7(i) proceeding. When BPA's witnesses were cross-examined regarding their knowledge of the purported imperfections that exist in the California ISO, BPA's witnesses acknowledged some familiarity with these market imperfections in cross-examination, Tr. 1206-07, although PPC asserts that BPA witnesses, in fact, "are unfamiliar with the California ISO market . . ." PPC Brief, WP-02-B-PP-1, at 37.

PPC's argument concerning market imperfections in the California ISO is not persuasive and does not establish an evidentiary basis upon which BPA is willing to reject its use of the California ISO. BPA witnesses testified that BPA is part of a larger west coast system and that the California markets are relevant to BPA. Tr. 1206-07. To the extent the California market affects BPA, the magnitude of prices within that market is relevant to BPA even if at any point in time it may be due to some market imperfections. *Id*. Furthermore, use of the California ISO is reasonable and appropriate, because fixed charges are inadequate to serve as a deterrent against unauthorized increases in the current market. Tr. 1214. Experience with the market has indicated that a single price may not necessarily be as strong a disincentive as believed when it is set, particularly when it is to be in effect for five years. *Id*. This consideration supports the need, first of all, for some index-based component for the UAI Charge for demand. Keep *et al.*, WP-02-E-BPA-43, at 30-31. The California ISO is the only west coast market for demand services and, among the California ISO ancillary services products, the hourly Spinning Capacity Reserve prices most closely approximate the kind of service BPA must provide to an unauthorized increase in demand. Further, the DJ Mid-C price indexes, while appropriate for inclusion in the UAI Charge methodology as a PNW index, historically have not even attained to BPA's proposed minimum UAI Charge for energy of 100 mills/kWh. Wholesale Power Rate Development Study Documentation, Volume 2, WP-02-E-BPA-05B, at 90. This is due in part to the diurnal nature of the DJ Mid-C indexes, which will tend to mask higher hourly energy values at times. An hourly index, again, is necessary to provide some comparability with the real-time circumstance confronting BPA when serving an unauthorized increase. Keep *et al.*, WP-02-E-BPA-17, at 18. Given the absence of a PNW hourly price index for energy, it is appropriate for the UAI Charges for energy to incorporate an hourly index for energy at some market accessible by Northwest parties.

PPC's testimony and initial brief both indicate that, in fact, the California ISO is conducting a redesign of its markets to address the market imperfections. Opatrny *et al.*, WP-02-E-PP-02, at 21; PPC Brief, WP-02-B-PP-01, at 35. PPC also states that there is no evidence that the redesigned markets will function any better than the current California ISO markets. Opatrny *et al.*, WP-02-E-PP-02, at 21-22. However, the appropriateness of the California ISO indexes need not rest on the success of the California ISO's efforts to resolve the market imperfections that have characterized its early history. The ultimate price levels themselves are more relevant than their underlying determinants in defining BPA's cost exposure. Keep *et al.*, WP-02-E-BPA-43, at 31; Tr. 1206-07. Periods of high prices in California would potentially expose BPA to high opportunity costs or, under some scenarios, high purchase costs associated with providing service to an unauthorized increase, irrespective of the underlying reasons. Keep *et al.*, WP-02-E-BPA-43, at 25. It is also the case that such a period of high prices, whether driven by market impurities or not, would feature the greatest opportunities for customers to profit by arbitraging unauthorized increases if the design of UAI Charges does not incorporate these indexes. Tr. 1214.

In arguing that a forecast BPA power surplus invalidates the use of California ISO indexes during periods of high market prices, SUB Brief, WP-02-B-SP-01, at 7-8, SUB Ex. Brief, WP-02-R-SP-01, at 9-10, SUB ignores the potential incentives during such periods for arbitraging unauthorized increases into the California markets. SUB's reliance on the shape of BPA's forecast surplus in arguing against the use of the California ISO indexes further ignores the central intent of the UAI Charges, which is to ensure that there is always a penalty, or deterrent, against placing unauthorized increases on BPA's system. Tr. 1214. Inclusion of the California ISO indexes in the UAI Charge methodology is necessary to preserve that deterrent, as well as protecting BPA against undue costs associated with customers placing unauthorized increases on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 25; Tr. 1212.

Finally, in supporting its arguments against the inclusion of the California ISO indexes, SUB presents five points in its brief on exceptions that collectively cite a California ISO report; BPA's rebuttal testimony statements on the seasonality of California ISO prices and imperfections in the California markets; Keep *et al.*, WP-02-E-BPA-43, at 30-31; BPA's Loads and Resources Study; and the qualifications of BPA's witnesses sponsoring the UAI Charge testimony. SUB Ex. Brief, WP-02-R-SP-01, at 9-10. SUB gives no explanation of the meaning for the five enumerated points. BPA is unable to ascertain their meaning and, therefore, they fail to support a conclusion one way or the other regarding the appropriateness of BPA's proposed incorporation of the California ISO indexes in its UAI Charge framework. In summary, SUB has failed to adequately support its arguments against the inclusion of the California ISO indexes.

PPC argues that because the Mid-C market hub is the most reflective of costs and market values in the PNW (and because BPA uses the Mid-C hub for cost classification between demand and energy charges and seasonal differentiation and diurnal differentiation, and the fact BPA does more transactions at Mid-C than through the California ISO), it should be used in establishing the costs to BPA when imposing UAI Charges. PPC Brief, WP-02-B-PP-01, at 37-38; PPC Ex. Brief, WP-02-R-PP-01, at 8. In its direct testimony, PPC argued for reliance only on DJ Mid-C indexes by citing statements in a data response by BPA staff sponsoring the MCA. This BPA data response states that "the Mid-C trading hub was selected because of the available hubs in this analysis, Mid-C is the most representative of the relevant power prices in the PNW." Opatrny *et al*., WP-02-E-PP-02, at 22-23, citing Response to Data Request PP-BPA:082. BPA's MCA witnesses were correct in their response. Tr. 1212. However, the context for their response was the design of standard rates for requirements service under BPA's core power products, and that response cannot be generalized to charges for service beyond subscribed product purchases. *Id.*; Keep *et al*., WP-02-E-BPA-43, at 25. When BPA must provide service to an unauthorized increase, its cost exposure at times is best defined by prices in the California markets. *Id.*; Tr. 1206-07, 1212. Further, the California indexes may be necessary at certain times to set the UAI Charges at a level that deters customers from exceeding their contractual entitlements to place loads on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 25-26.

In arguing for exclusive use of Mid-C indexes, PPC also notes that BPA conducts a much higher volume of transactions at the Mid-C hub than it does in the California ISO markets. PPC Brief, WP-02-B-PP-01, at 37. BPA staff acknowledged that BPA conducts a far greater volume of transactions at the Mid-C hub than at the California ISO, while qualifying that the relative mix of transactions could change in the future. Tr. 1209-10. In spite of PPC's observations, the appropriateness of a particular index for purposes of the UAI Charges does not rest on the number or volume of transactions represented by that index. What is more relevant is the circumstances of those transactions. In the case of UAI Charges, the California ISO indexes reflect hour-ahead transactions that most closely resemble the real-time basis of service to demand and energy overruns by BPA's customers. Keep *et al.*, WP-02-E-BPA-17, at 18. By definition, BPA's transactions at Mid-C preclude real-time or even hour-ahead transactions; rather, they would be comprised of a mix of day-ahead transactions and transactions encompassing longer periods, as long as several years. Therefore, the number or volume of transactions at a particular hub has little relevance to the appropriateness of the associated price index(es) for use in the UAI Charges.

The California ISO Supplemental Energy and Spinning Reserve Capacity price indexes, aside from reflecting hour-ahead transactions that among available indexes most closely approximate the real-time nature of service to unauthorized increases, are for the common commodities, specifically energy and capacity, for which BPA is developing the UAI Charges. Despite the market imperfections that drive California ISO prices at times, their inclusion in the UAI Charge methodology is both reasonable and necessary in light of BPA's cost exposure, Keep *et al.*, WP-02-E-BPA-43, at 25; and BPA's need for a deterrent against demand and energy overruns placed on BPA's system. *Id*. at 25-26; Tr. 1213-14.

Decision

It is appropriate for BPA to use California ISO price indexes in its UAI Charges for demand and energy.

Issue 3

Whether the UAI Charges for energy and demand should be based upon market price indexes for the precise period when an unauthorized increase occurs.

Parties' Positions

PPC argues that BPA's proposed design of UAI Charges for demand and energy is flawed because "they are not based upon the market price at the time of the unauthorized increase." PPC Brief, WP-02-B-PP-01, at 35. In direct testimony, PPC stated its opposition to the use of market prices for the UAI Charges, while suggesting that BPA, at a minimum, base the charges on "the costs incurred at the time when the unauthorized increase occurs" rather than the highest prices realized in the Northwest and California markets for the month. Opatrny *et al.*, WP-02-E-PP-02, at 18-19. PPC argues that assuming the California ISO ancillary service market is robust, BPA has laid an inadequate foundation for the UAI Charge as a penalty charge. PPC Brief, WP-02-B-PP-01, at 35. PPC asserts that BPA's design of the "penalty charge" is apparently ignorant of FERC precedent defining penalty charges. *Id.* In its brief on exceptions, PPC asserts that the UAI charges were "designed without consideration of FERC precedent regarding appropriate penalty charges for ancillary services . . ." PPC Ex. Brief, WP-02-R-PP-01, at 7.

SUB proposes that the UAI Charges for demand be fixed at three times the applicable standard demand charge for the month. Nelson, WP-02-E-SP-01, at 5; SUB Brief, WP-02-B-SP-01, at 8. SUB proposes that the UAI Charges for energy be tied to "the cost of providing [unauthorized increase] service over the period" in which the unauthorized increase occurred, rather than on the highest market price index during a billing month. Nelson, WP-02-E-SP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8. SUB supports a "pass-through-cost basis" in which the UAI Charges for demand and energy would apply only in those instances when FBS resources, both firm and nonfirm, are insufficient to meet demand or energy overruns; SUB contends that standard demand and energy charges should apply when FBS resources are sufficient to meet overruns. Nelson, WP-02-E-SP-01, at 5-6, 8.

OURCA does not specifically address this issue, but "adopts and joins" the positions stated in PPC's initial brief with regard to the UAI Charges. OURCA Brief, WP-02-B-OU-01, at 7.

BPA's Position

For energy overruns, BPA proposed that the UAI Charge for energy for a given month be the greatest of 100 mills/kWh, the highest DJ Mid-C price for the month, or the highest California ISO Supplemental Energy price for the month. Keep *et al.*, WP-02-E-BPA-17, at 17-18; Keep *et al.*, WP-02-E-BPA-43, at 24. BPA opposed a time-specific passthrough of costs tied to the market value of power at the time of an unauthorized increase. Keep *et al.*, WP-02-E-BPA-43, at 27-30.

BPA proposed that the UAI Charge for demand be the greater of three times the applicable standard demand charge for the month and the sum of the hourly ISO Spinning Reserve Capacity prices for all HLH during the month. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 24. By definition, BPA's proposed penalty for demand overruns would not be specifically driven by the highest hourly ISO Spinning Reserve Capacity price index for a given billing month; rather, the penalty would convert this hourly price index to a monthly index-based charge by summing all HLH prices for the month. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108.

BPA also opposes SUB's position that application of UAI Charges for demand and energy be contingent on BPA's resource sufficiency at the time of an unauthorized increase. Keep *et al.*, WP-02-E-BPA-43, at 28-29.

Evaluation of Positions

PPC characterizes BPA's proposed UAI Charges for demand and energy as flawed, because they are not based upon market prices at the time of the unauthorized increase. PPC Brief, WP-02-B-PP-01, at 35. In its direct testimony, PPC cites precedents in the gas industry and other power marketing administrations (*e.g.*, SWPA and Western Area Power Administration (WAPA)) to support time-specific passthrough cost bases for overrun penalties. Opatrny *et al.*, WP-02-E-PP-02, at 19.

SUB cites SWPA's P-98 B rate schedule in support of its proposal for a fixed penalty charge for demand that is applicable only when BPA resources are not sufficient to meet a customer's demand at the time of the overrun. Nelson, WP-02-E-SP-01, at 6; SUB Brief, WP-02-B-SP-01, at 8. SUB cites the WAPA-78 rate order to argue that the UAI Charges for energy should be based on the DJ Mid-C price indexes for the hour in which the unauthorized increase in energy occurred, and that only standard charges for energy be levied for those occurrences when BPA resources are sufficient to meet the energy overrun. Nelson, WP-02-E-SP-01, at 7-8; SUB Brief, WP-02-B-SP-01, at 8.

PPC's assertion that the UAI Charges for demand are not based upon the market price at the time of the increase, PPC Brief, WP-02-B-PP-01, at 35, is accurate. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108. For the index-driven penalty charges for demand, BPA proposed to sum the hourly California ISO Spinning Reserve Capacity prices for all HLH in a given billing month. BPA proposed that this index-based charge would be the effective charge if greater than three times the effective standard Demand Charge for the month. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al*., WP-02-E-BPA-43, at 24. This construct for the penalty charges for demand merely converts an hourly index for Spinning Reserve Capacity prices to the same monthly basis as the standard demand charges. Without this conversion, the maximum index-based penalty charge for demand overruns, as defined by the California ISO's current price cap for hourly Spinning Reserve Capacity, would be $0.75/kW/hr. In comparison to BPA's proposed average monthly demand charge of $2.00/kW/mo., this hourly charge is a price that is clearly too low to represent a deterrent against demand overruns. Further, while arguing that BPA's proposed design for UAI Charges for demand is flawed because the charges are not based on the market prices at the time of the demand overrun, PPC fails to acknowledge that BPA's service to a demand overrun for one hour constitutes a monthly service. In fact, the appropriate underlying assumption is that, similar to demand within a customer's contractual entitlement that is billed at the standard monthly charges, any service that BPA must provide to a demand overrun is a monthly service. BPA's standard demand charges apply to monthly service, and are billed on a $/kW-month basis. Keep *et al.*, WP-02-E-BPA-17, at 2-3. Therefore, in order to provide a meaningful index-based penalty, it is appropriate to sum all the hourly ISO Spinning Reserve Capacity prices for all HLH of the month.

In asserting flaws in the proposed design of the UAI Charges for demand and energy, PPC cites the cross-examination transcript, Tr. 1201, and the Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108, in stating that the unauthorized increases in demand may be determined on an hourly basis, and unauthorized uses of energy may be determined on an hourly or diurnal basis. PPC Brief, WP-02-B-PP-01, at 35. As a point of clarification, Section II.V. of the GRSPs addresses the determination of the UAI Charges for demand and energy, Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108-09, while the quantifications of demand and energy overruns are dependent on the product. Tr. 1198-99.

SUB suggests that BPA base its UAI Charges consistent with similar charges assessed by other Federal Power Marketing Agencies (PMAs). SUB Brief, WP-02-B-SP-01, at 8. The basis for penalty charges assessed by other PMAs has little applicability to BPA's situation; those entities have their own reasons for setting charges. Keep *et al*., WP-02-E-BPA-43, at 27. Unlike the two PMAs cited by PPC and SUB, BPA is obligated to meet the full net requirements of its wholesale utility customers. *Id.* Neither WAPA nor SWPA is similarly obligated; instead, they allocate Federal power from a finite pool of resources that can meet only a portion of their customers' firm requirements. *Id.* In contrast, BPA must stand ready to provide emergency supply service on an instantaneous basis, creating a cost exposure for BPA that other PMAs do not have. *Id.* at 27-28.

Both PPC and SUB argue that BPA's penalty charge should be consistent with FERC precedent regarding penalty charges. PPC Brief, WP-02-B-PP-01, at 35-37; PPC Ex. Brief, WP-02-R-PP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8. PPC cites several FERC decisions regarding penalty charges: *New York State Electric & Gas Corp*., 79 FERC ¶ 61,371, 62,548-49 (1997); *Allegheny Power System*, 80 FERC ¶ 61, 045, 61,545-47 (1997), *New England Power Pool*, 83 FERC ¶ 61,045, 61,235 (1998); *Houston Lighting & Power Co*., 77 FERC ¶ 61,113, 61,439 n. 16 (1996); *Houston Lighting & Power Co*., 81 FERC ¶ 61,015 (1997); *Southwest Power Pool*, 86 FERC ¶ 61,090, 61,328, 61,330 (1999); *American Electric Power Company and Central and Southwest Corporation*, 85 FERC ¶ 61,201, 61,809, 61,824 (1998); and *Detroit*

Edison Company, 84 FERC ¶ 63,006, 65,043, 65,046 (1998). OURCA also cites *Allegheny Power System, Inc., et al*., 80 FERC ¶ 61,143, and *Detroit Edison Company*, 84 FERC ¶ 63,006 (1998). The decisions cited involve gas and electric utilities regulated by FERC. Many of these cases concern charges and rates concerning *pro forma* transmission tariffs. Unlike FERC's authority under the FPA or the Natural Gas Act to regulate such utilities, the statutory mandate accorded to FERC under the power marketing acts does not provide FERC such authority. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, at 61,340 (1980). Therefore, the cases cited by PPC have no precedential value; however, BPA may look to such cases for guidance.

BPA has had FERC approval to charge up to 100 mills/kWh for UAI Charges for over 20 years. *Id*. BPA is not persuaded by the cases cited by the parties to reject the foundation for BPA's UAI Charges. BPA is modifying these charges because as currently established they do not accurately reflect the costs to BPA caused by customers exceeding their contractual entitlement to take power. Keep *et al*., WP-02-E-BPA-17, at 15. The UAI Charge for energy in the 1996 rates was 100 mills/kWh. *Id*. The UAI Charge for demand in the 1996 rates was the effective standard Demand Charge, or $0.87/kW-month. *Id*. Since 1996, a robust wholesale power market has developed in which the 1996 UAI Charges simply do not perform as intended. *Id*. BPA has changed these charges to give BPA the flexibility to assess charges that reflect the volatility of the market in periods in which the market price for power exceeds the minimum UAI Charges for energy and demand. *Id*.

BPA's ability to plan its service obligations for the core Subscription products, as specified in the power sales contracts, and to control its costs depends on customers accurately specifying the demand and energy obligations that BPA must serve. Keep *et al.*, WP-02-E-BPA-17, at 17. The penalty aspect of BPA's UAI Charges is essential to deter customers from exceeding their contractual right to place load on BPA's system and to motivate customers to purchase the right product mix rather than to rely on unauthorized increases as an economic product choice. Keep *et al.*, WP-02-E-BPA-43, at 33. BPA does not want to undermine appropriate incentives for customers to purchase in advance products and services they need. Keep *et al*., WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 33; Tr. 1214. The application of charges tied to "market value" at the time of the unauthorized increase would undermine the deterrent nature of the charges. Keep *et al.*, WP-02-E-BPA-43, at 29. Limiting the penalty charges to the market price of power, as measured by some specified price index, on the hour or date of an unauthorized increase would increase the likelihood that the customer responsible for the overrun would experience no economic cost as a result of the overrun. *Id.* at 28-29. BPA recognized the developments in the open power markets in recent years in designing the UAI Charges to preclude an incentive for customers to arbitrage unauthorized increases and achieve profits during periods when market prices are high. Tr. 1213-14. Finally, the UAI Charges are intended to protect BPA from market cost exposure resulting from occurrences of unauthorized increases. Keep *et al.*, WP-02-E-BPA-17, at 16-17; Keep *et al.*, WP-02-E-BPA-43, at 29-31; Tr. 1212.

There is additional justification for not limiting the UAI Charges to the market value of power at the precise time of the unauthorized increase. With respect to UAI Charges for energy, energy overruns generally are determined on a monthly basis. Keep *et al.*, WP-02-E-BPA-43, at 29-30;

Tr. 1198-1199. The exception is the case of a Simple Partial customer that fails to deliver a resource on a given hour. *Id.* at 1199. Therefore, PPC's and SUB's proposal is not administratively feasible. Keep *et al.*, WP-02-E-BPA-43, at 29-30. Further, basing the UAI Charges for energy at the market value at the time of the overrun may underrecover BPA's cost of serving the overrun. There are cost impacts associated with unauthorized increases to BPA, even if BPA is not in the market. BPA could be forced to run water to generate in order to serve unauthorized increases during a less expensive period, resulting in BPA without adequate water to generate at a later time when market prices are higher. *Id.* at 28-29. While BPA's primary intent underlying its UAI Charges is to establish a penalty rate that provides a deterrent against demand and energy overruns, protection against such potential cost exposure is also an important component in the UAI Charges. Tr. 1212.

SUB's argument for application of standard demand and energy charges when BPA has sufficient resources to serve an unauthorized increase is without merit. First, identifying the hour or day when an unauthorized increase in energy occurs is generally not feasible. There is a problem of identifying during which hour or day an unauthorized increase in energy occurred when the determination involves a customer's total energy take during an entire billing month. Keep *et al.*, WP-02-E-BPA-43, at 28. Second, even in those instances when an unauthorized increase can be associated with a given hour, the cost implications to BPA are not confined to that hour, particularly if the system resources BPA expends to serve the unauthorized increase are unavailable during a subsequent higher cost period. *Id.* at 28-29. Third, SUB's argument completely ignores the need for the UAI Charges to provide a sufficient penalty to deter customers from placing demand and energy overruns on BPA's system. *Id.* at 29. To the contrary, in conjunction with other elements of SUB's proposal, a customer would know *a priori* that the most it would pay for unauthorized increases in energy at any point in time would be the DJ Mid-C index for that period and, in many cases, the customer would face only standard energy charges. *Id.* Similarly, a customer would know that the maximum charge for a demand overrun would be three times the standard demand rate, with a significant probability that it would face only the standard demand charge. SUB's proposal, in effect, would alter the design of the UAI Charges in a way that would make demand and energy overruns an economic alternative to customers, undermining their incentive to operate their systems in a fashion that avoids unauthorized increases and to make appropriate product purchases. *Id.* BPA rejects SUB's proposal that only standard demand and energy charges would apply when BPA has sufficient resources to serve unauthorized increase in demand or energy.

The need to preserve the penalty aspect of the UAI Charges and the need to maintain protection against cost exposure associated with energy overruns support basing the UAI Charges for energy on the highest market price index for the billing month (subject to the 100 mills/kWh minimum; see next Issue). BPA proposed the use of the monthly maximum DJ Mid-C price index and the monthly maximum California ISO Supplemental Energy price indexes in the design of its UAI Charges for energy. The same imperatives for a penalty component and protection against cost exposure govern the design of the UAI Charges for demand. The design of BPA's UAI Charges for demand is not tied to the market price at the time of a demand overrun; rather, the design simply converts the hourly California ISO Spinning Reserve Capacity price indexes to a monthly basis to correspond with the monthly service BPA provides to a demand overrun for any hour. Finally, the UAI Charges should apply in all cases when an unauthorized increase occurs.

Decision

The UAI Charges for energy and demand are not based upon market price indexes for the precise period when an unauthorized increase occurs.

Issue 4

Whether the UAI Charges for demand and energy should include a "floor."

Parties' Positions

PPC argues that the UAI Charge is objectionable for being asymmetrically based on the greater of a floor or a market. PPC asserts that if BPA may charge the market price for an unauthorized increase when the market prices are high, BPA should similarly charge a market price when those prices are low. PPC Brief, WP-02-B-PP-01, at 37. PPC asserted in direct testimony that the 100 mills/kWh floor charge for energy overruns should be eliminated. Opatrny *et al.*, WP-02-E-PP-02, at 23.

SUB proposes that the UAI Charges for demand be fixed at three times the applicable demand charges for a specific month. Nelson, WP-02-E-SP-01, at 5-6; SUB Brief, WP-02-B-SP-01, at 8. SUB essentially proposes to fix the UAI Charges for demand at BPA's proposed floor. SUB further proposes that the floor for the UAI Charges for energy be eliminated, and that BPA charge 100 mills/kWh only in the case where the DJ Mid-C Indexes cease to exist. Nelson, WP-02-E-SP-01; at 8; SUB Brief, WP-02-B-SP-01, at 8.

OURCA presents no specific proposal regarding the floor charges for demand and energy overruns. However, OURCA asserts that the UAI Charges should be eliminated or revised, and adopts and joins positions stated in the PPC Brief with respect to the UAI Charges. OURCA Brief, WP-02-B-OU-1, at 7.

BPA's Position

BPA proposed a minimum charge for unauthorized increases in demand equal to three times the applicable monthly demand charge. Keep *et al.,* WP-02-E-BPA-17, at 17; Keep *et al.,* WP-02-E-BPA-43, at 24. BPA proposed a minimum charge of 100 mills/kWh for the unauthorized increases in energy. Keep *et al.*, WP-02-E-BPA-17, at 17.

Evaluation of Positions

PPC asserts that BPA's UAI Charge design is asymmetrical given that it includes floor charges in conjunction with market-based charges. PPC Brief, WP-02-B-PP-01, at 37. PPC further argues that if BPA levies market-based charges during periods of high market prices, it should similarly charge market prices when those prices are low. *Id.* PPC argues that BPA should collect only the costs that it incurs. Opatrny *et al*., WP-02-E-PP-02, at 23. PPC asserts that BPA should not experience a windfall from unauthorized increases when market prices are low, and that if BPA relies upon market indexes for determining "the extent to which it is harmed, then a floor is unnecessary." *Id.*

SUB cites the SWPA's P-98 B rate schedule to support its proposal that the UAI Charge for demand should be fixed at three times the applicable monthly demand charge, a penalty charge that would be applicable only in those instances where BPA has insufficient resources to serve an unauthorized increase in demand. Nelson, WP-02-E-SP-01, at 5-6; SUB Brief, WP-02-B-SP-01, at 8. SUB cites the WAPA-78 rate order in arguing against the floor for the UAI Charges for energy. Nelson, WP-02-E-SP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8.

PPC's arguments that BPA should collect only the costs that it incurs and SUB's arguments for a passthrough cost basis for the penalty charges ignore the need for a meaningful penalty component that deters customers from placing unauthorized increases on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 33. The UAI Charges are penalty charges. Tr. 1200. While protection against BPA's cost exposure is a consideration in the design of the UAI Charges, the penalty aspect in the charges is necessary to motivate customers to purchase products and services to ensure that they do not place loads on BPA beyond their contractual rights, and not to use unauthorized increases as an economic alternative to those products and services. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 28-29; Tr. 1213-14. BPA's ability to plan its service obligations for the core Subscription products and to control its costs depends on customers accurately specifying the obligations that BPA must serve, both demand and energy. Keep *et al.*, WP-02-E-BPA-17, at 17. Any occurrences of unauthorized increases undermine BPA's ability to plan its service obligations and control its costs. *Id.*

Further, the minimum charges may be necessary to ensure that the penalty charges are high enough to provide a meaningful deterrent. For instance, the historical data show that index-based charges for demand, had they been in place in February 1999, would have been $1.52/kW/mo., or less than BPA's proposed February PF Demand charge for the 2002 rates. Keep *et al.*, WP-02-E-BPA-17, at 16; Volume 2, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 75. Similarly, the index-based UAI Charge for energy for January 1999 would have been 53 mills/kWh, less than the current fixed charge of 100 mills/kWh. Keep *et al.*, WP-02-E-BPA-17, at 16; Volume 2, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 90. The minimum charges are necessary to ensure that the penalty component is in place during all periods sufficient to deter customers from placing energy and demand overruns on BPA's system.

The minimum UAI Charges for demand and energy ensure that some penalty will be in place for unauthorized increases in the unlikely event that the proposed indexes cease to exist and suitable successor indexes are unavailable. Keep *et al.*, WP-02-E-BPA-17, at 17.

SUB's proposal for standard charges to govern when BPA has sufficient resources to serve unauthorized increases undermines the deterrent elements of the UAI Charges, does not protect BPA from undue cost exposure, and is administratively impractical. Keep *et al.*, WP-02-E-BPA-43, at 28-29. (*See* previous Issue.)

Decision

BPA's floor components for the UAI Charges for demand and energy are necessary.

10.7 Excess Factoring Charges

BPA proposed two new penalty charges related to BPA's factoring service for core Subscription products. *See* Keep *et al*., WP-02-E-BPA-17, at 19. The term "factoring" refers to the service of shaping a given quantity of energy among either HLH or LLH of a period (*i.e*., day or month) to follow load. *Id*. Only when customer resources have hour-to-hour variability is there a possibility of receiving factoring service amounts which are less or greater than the entitlement amount. *Id*. Factoring service is a bundled component of Subscription core products for Full Service and Actual Partial Service. For purposes of administering the Actual Partial Service-Complex product, which involves serving customers with variable resources, a factoring benchmark test would be done in the billing process. *Id*.

In its initial brief, PPC argued that the Excess Factoring Charge "suffers from flaws which mirror the just-described flaws in the unauthorized increase charge." PPC incorporated its analysis of the UAI Charges into its argument on the Excess Factoring Charge regarding the lack of cost basis for the charge; use of the imperfect California ISO ancillary services market in lieu of a cost basis; the absence of foundation to support such a "penalty" charge; and the asymmetric design of the charge. BPA addresses each issue in turn. Because the PPC relies on the same arguments it made concerning the UAI Charges for purposes of addressing the Excess Factoring Charge, BPA finds it necessary to also reference its testimony regarding the UAI Charges where applicable.

Issue 1

Whether BPA lacks the authority to impose an Excess Factoring Charge that is not reflective of BPA's cost.

Parties' Positions

PPC incorporates its argument regarding the UAI Charges and similarly argues that the Excess Factoring Charge is not cost-based as required by BPA's statutes. PPC Brief, WP-02-B-PP-01, at 38. OURCA argues that BPA lacks the authority to impose penalties without some basis tied to the underlying service and the associated costs that BPA may incur. OURCA asserts that the charges should be eliminated or revised. OURCA Brief, WP-02-B-OU-01, at 7.

PPC reiterated its argument that the Excess Factoring Charge is not based on BPA's costs, as required by statute. They claim that BPA arbitrarily rejected this argument. PPC Ex. Brief, WP-02-R-PP-01, at 8.

OURCA also reiterates its argument that BPA does not have the authority to adopt the excess factoring penalties in the Draft ROD without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA adopts and joins the position of the PPC as stated in PPC's brief on exceptions. OURCA Ex. Brief, WP-02-B-OU-01, at 6.

<u>BPA's Position</u>

The Excess Factoring Charge operates similarly to the UAI Charges, and is intended to be a penalty rather than a cost recovery mechanism. Keep *et al*., WP-02-E-BPA-43, at 34. It is a charge for use of more of a service than allowed in the product being purchased. *Id*. The Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specified limits and, secondarily, to protect BPA from cost exposure in those instances where Excess Factoring does occur. *See* Keep *et al*., WP-02-E-BPA-17, at 21-22. Therefore, as in the case of Unauthorized Increase, the intent of the Excess Factoring Charge is to assure it does not appear to a customer that it would be more economical to exceed the product limits and pay the Excess Factoring Charges than to arrange up front for a product of a reserve nature. Tr. 1214.

<u>Evaluation of Positions</u>

PPC argues that the foundation for BPA's proposed Excess Factoring Charge is suspect, because it is not based on BPA's cost as required by statute. PPC Brief, WP-02-B-PP-01, at 37. OURCA similarly contends that BPA lacks authority to impose these penalties without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA Brief, WP-02-B-OU-01, at 7. Neither party provided specific analysis to support the claim that BPA lacks authority to impose the Excess Factoring Charge. As already discussed with respect to the UAI Charges, BPA has the authority to impose non-cost based penalty charges. This is equally applicable to the imposition of the Excess Factoring Charges.

The UAI Charge provides a precedent to the Excess Factoring Charge. Since its inception in 1974, the UAI Charge has been developed to be a penalty and not a cost-based rate. *See* 1993 ROD, WP-93-A-02, at 169. FERC has recognized the Administrator's authority to impose an UAI Charge that is not cost-based. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,340 (1980). FERC approved BPA's UAI Charge of 100 mills/kWh in the 1970s, when costs were less than 5 mills/kWh. 1993 ROD, WP-93-A-02, at 171. FERC predicated its approval on the fact that the UAI Charge was designed to modify customers' behavior. *Id*. FERC took notice of the fact that the charge was developed to assure that BPA's customers used their own resources first to meet their firm system load obligations. *Id*. As such, FERC noted that such a charge also ensures that the power BPA's customers marketed to others was truly excess resource capability. *Id*.

Similarly, BPA has determined the need for the Excess Factoring Charge as a penalty charge to discourage excess use of factoring. Keep *et al*., WP-02-E-BPA-43, at 36. When BPA is forced to provide factoring service beyond that specified by the products that the customer has purchased, that extra service can necessitate real-time adjustments that burden BPA's system and can have cost consequences to BPA. Keep *et al*., WP-02-E-BPA-17, at 21. This is especially true if a customer's excess factoring represents a shift from lower-cost periods of the day or month to higher-cost periods. *Id*. When Within-Day and Within-Month Excess Factoring has occurred, BPA has in effect provided a shaping service associated with the customer's resources rather than its load. *Id*. at 22-23. The Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specific limits and, specifically, to protect BPA from cost exposure in those instances where Excess Factoring occurs. *Id*. at 22.

It is appropriate for the Excess Factoring Charge to provide a penalty rather than be tied to some cost basis. BPA adopts the principle of penalty-based Excess Factoring Charges. Additionally, the Excess Factoring Charges need to provide a sufficiently strong price signal to customers to plan and operate their systems in a fashion that avoids placing excess factoring on BPA's system.

BPA does not agree that it has acted in an arbitrary, capricious, or discriminatory manner as alleged by some parties. BPA's decisions are supported by the evidence in the record and are well reasoned and analyzed.

<u>Decision</u>

BPA has the authority to impose Excess Factoring Charges that are not reflective of BPA's costs.

<u>Issue 2</u>

Whether the use of California ISO price indexes is appropriate for the Excess Factoring Charges.

<u>Parties' Positions</u>

In its comments on the Excess Factoring Charge, PPC incorporates its argument regarding the use of California ISO Spinning Capacity Reserve and Supplemental Energy indexes for the UAI Charges, and similarly argues that the ISO is demonstrably unreliable as it pertains to the Excess Factoring Charge. PPC Brief, WP-02-B-PP-01, at 38.

The Market Access Coalition Group (MAC) supports PPC's testimony on the Excess Factoring Charge. MAC states: "As explained by Ms. Opatrny, BPA should base the ceiling charges for excess factoring on Mid-C energy index prices, not California ISO prices." MAC Brief, WP-02-B-MA-01, at 15.

OURCA states that the Unauthorized Increase and Excess Factoring charges should be revised or eliminated. OURCA Brief, WP-02-B-OU-01, at 7. OURCA adopts and joins the position of PPC as stated in their initial brief with regard to the UAI Charges and the Excess Factoring Charge. *Id*.

<u>BPA's Position</u>

While BPA agrees that DJ Mid-C indexes are appropriate for development of rates for requirements service, BPA does not agree that the availability of such indexes limits BPA's application of the ISO indexes for determining the Excess Factoring Charge. Keep *et al*., WP-02-E-BPA-43, at 35. The Excess Factoring Charge is intended to be a penalty charge that discourages excess use of factoring, and it should be calculated at a minimum to offset any financial gains that the customer could achieve. Keep *et al*., WP-02-E-BPA-43, at 36.

Evaluation of Positions

As with PPC's arguments regarding the UAI Charges, PPC similarly argues that Excess Factoring must be consistent with the theory that BPA should recover actual costs. PPC Brief, WP-02-B-PP-01, at 36. "In summary, the foundation for BPA's proposed UAI charge is suspect, for it is not based on BPA's cost as required by statute . . ." *Id*. at 37. MAC supports PPC and notes that "BPA should be charging the cost that it incurred for providing service, and therefore, the charge should reflect conditions when the excess factoring occurred." MAC Brief, WP-02-B-MA-01, at 15, quoting Opatrny, WP-02-E-PP-02, at 24. OURCA adopts and joins PPC's position. OURCA Brief, WP-02-B-OU-01, at 7. The parties contend that BPA should base the ceiling charges for excess factoring on Mid-C energy index prices, not California ISO prices. PPC Brief, WP-02-B-PP-01, at 38; MAC Brief, WP-02-B-MA-01, at 15.

For the same reasons given by BPA in support of the UAI Charges, the Excess Factoring Charge is a penalty rather than a cost recovery mechanism. Keep *et al*., WP-02-E-BPA-43, at 34. BPA does not agree that the DJ Mid-C indexes should be used for determining the Excess Factoring Charge. *Id*. at 36. BPA's inclusion of ISO indexes in its Excess Factoring Charge recognizes that the markets drive its cost exposure, and there are times when this market-driven cost exposure is more closely tied to the California markets. *Id*. Also, since the Excess Factoring Charge, like the UAI Charges, is intended to be a penalty charge that discourages excess use of factoring, it should be calculated at a minimum to offset any financial gains that the customer could achieve. *Id*.; Tr. 1214.

MAC asserted that the within-day charges should be based on daily prices, not monthly prices. MAC Brief, WP-02-B-MA-01, at 15. However, BPA's within-day excess factoring charges are based on neither daily nor monthly prices. BPA is using hourly prices to calculate its within-day factoring charge. BPA uses "the maximum Within-Day difference" that occurs "during the month." Keep *et al.*, WP-02-E-BPA-17, at 22. Using the maximum difference found during the month assures that the penalty charge will provide a disincentive to customers to rely on Excess Factoring as a product. It is unclear to BPA, because of the manner in which PPC incorporated its UAI Charge analysis, whether timing is an issue with the Excess Factoring Charge. Nonetheless, in response to whether timing is an issue, BPA is implementing a reasonable method to base the Excess Factoring Charge as already explained.

PPC cites to reports that purportedly demonstrate the imperfections of the California ISO. PPC cites the California ISO's *Report on Redesign of California Real-Time Energy And Ancillary Services Markets* in asserting that there are market imperfections in the California ISO markets. Opatrny *et al*., WP-02-E-PP-02, at 20. PPC also cites an additional California ISO Report, *Second Report on Market Issues in the California Power Exchange Energy Markets*, March 1999, which documents FERC's recognition of the need for price controls in the California ISO ancillary services markets. PPC Brief, WP-02-B-PP-01, at 34-35. PPC also documents FERC's November 1999 extension of price cap authority for an additional year for the California ISO markets to allow for market redesign. *Id*. at 35. These reports have no evidentiary weight, and have not been entered into evidence by any party in this section 7(i) proceeding.

PPC's argument concerning market imperfections in the California ISO is not persuasive and does not establish an evidentiary basis upon which BPA is willing to reject its use of the California ISO. While BPA acknowledges current market imperfections at the ISO, Tr. 1206; Keep *et al*., WP-02-E-BPA-43, at 31; these imperfections do not undermine the California market's relevance to BPA's cost exposure. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1212. BPA witnesses testified that BPA is part of a larger west coast system, and that the California markets are relevant to BPA. Keep *et al*., WP-02-E-BPA-43, at 30; Tr. 1206-07. To the extent the California market affects BPA, the magnitude of prices within that market is relevant to BPA even if at any point in time it may be due to some market imperfections. *Id*. Furthermore, use of the California ISO is reasonable and appropriate, because fixed charges may not necessarily be as strong a disincentive over a period of time, particularly if such a charge is to be in effect for five years. Tr. 1214. And again, like the use of the California ISO in determining the UAI Charges, BPA intends the Excess Factoring Charge to be a penalty. Keep *et al.*, WP-02-E-BPA-43, at 36.

Likewise, BPA recognizes the need for an hourly index to set a charge for excess within-day factoring. The use of an hourly index to determine the highest Within-Day differences is a measure of the potential cost exposure to BPA associated with this excess factoring service. Keep *et al*., WP-02-E-BPA-17, at 22. The derivation of index driven charges for within-day Excess Factoring (which are to be compared to a defined minimum charge) are, by definition, reliant on some hourly index. Keep *et al*., WP-02-E-BPA-43, at 31. There is no PNW hourly price index currently available for performing these derivations. *Id*. Given the absence of a PNW hourly price index for energy, it is appropriate for the Within-Day Excess Factoring Charge to incorporate an hourly index for energy at some market accessible by Northwest parties.

The discovery and correction of market flaws in the California ISO does not disqualify it as the best available public index for products which are similar in nature to those which must be used to serve Excess Factoring usage. PPC's testimony and initial brief both indicate that, in fact, the California ISO is conducting a redesign of its markets to address the market imperfections. Opatrny *et al.*, WP-02-E-PP-02, at 21; PPC Brief, WP-02-B-PP-01, at 35. PPC also states that there is no evidence that the redesigned markets will function any better than the current California ISO markets. Opatrny *et al.*, WP-02-E-PP-02, at 21-22. However, as was discussed regarding the UAI Charges, the appropriateness of the California ISO indexes need not rest on the success of the California ISO's efforts to resolve the market imperfections that have characterized its early history. The ultimate price levels themselves are more relevant than their underlying determinants in defining BPA's cost exposure. Keep *et al.*, WP-02-E-BPA-43, at 31; Tr. 1206-07. Periods of high prices in California would potentially expose BPA to high opportunity costs or, under some scenarios, high purchase costs associated with providing service to an unauthorized increase, irrespective of the underlying reasons. Keep *et al.*, WP-02-E-BPA-43, at 25. It is also the case that such a period of high prices, whether driven by market impurities or not, would feature the greatest opportunities for customers to profit by arbitraging unauthorized increases if the design of Excess Factoring Charges does not incorporate these indexes. Tr. 1214.

In its arguments against the UAI Charge, PPC argues that because the Mid-C market hub is the most reflective of costs and market values in the PNW (and because BPA uses the Mid-C hub for cost classification between demand and energy charges and seasonal differentiation and diurnal differentiation, and the fact BPA does more transactions at Mid-C than the California ISO) it should be used in establishing the costs to BPA when it imposes an UAI charge. PPC Brief, WP-02-B-PP-01, at 37-38. In its direct testimony, PPC argued for reliance only on DJ Mid-C indexes by citing statements in a data response by BPA staff sponsoring the MCA. This BPA data response states that "the Mid-C trading hub was selected because of the available hubs in this analysis, Mid-C is the most representative of the relevant power prices in the PNW." Opatrny *et al*., WP-02-E-PP-02, at 22-23; Response to Data Request PP-BPA:082. BPA's Marginal Cost Analysis witnesses were correct in their response. Tr. 1212. However, the context for their response was the design of standard rates for requirements service under BPA's core power products, and that response cannot be generalized to charges for service beyond subscribed product purchases. *Id.*; Keep *et al*., WP-02-E-BPA-43, at 25. When BPA must provide service to an excess factoring occurrence, its cost exposure at times is best defined by prices in the California markets. *Id.*; Tr. 1206-07, 1212. Further, the California indexes may be necessary at certain times to set the Excess Factoring Charges at a level that deters customers from exceeding their contractual entitlements to place loads on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 25-26.

In arguing for exclusive use of Mid-C indexes, PPC also notes that BPA conducts a much higher volume of transactions at the Mid-C hub than it does in the California ISO markets. PPC Brief, WP-02-B-PP-01, at 37. PPC's argument is not persuasive. BPA evaluated this argument with respect to the UAI Charges, and finds that evaluation equally applicable here. Both sets of charges are penalty charges intended to be a disincentive to relying on these charges as stand-ready products. BPA acknowledged that BPA conducts a far greater volume of transactions at the Mid-C hub than at the California ISO, while qualifying that the relative mix of transactions could change in the future. Tr. 1209-10. In spite of PPC's observations, the appropriateness of a particular index for purposes of the Excess Factoring Charges does not rest on the number or volume of transactions represented by that index.

BPA's inclusion of ISO indexes in its Excess Factoring Charge recognizes that the markets drive its cost exposure, and there are times when this market-driven cost exposure is more closely tied to the California markets. Also, since the Excess Factoring Charge is intended to be a penalty charge that discourages excess use of factoring, it should be calculated at a minimum to offset any financial gains that the customer could achieve. BPA does not want to price an excess use charge such that customers use it to make a profit elsewhere. Keep *et al.*, WP-02-E-BPA-43, at 36.

Decision

BPA adopts the use of California ISO price indexes in its Excess Factoring Charge.

Issue 3

Whether the Within-Day and Within-Month Excess Factoring Charges should be symmetrical by eliminating the floor.

Parties' Positions

PPC incorporates its analysis that the UAI Charge is objectionable for being asymmetrically based on the greater of a floor or a market, and argues that the Excess Factoring Charge is similarly asymmetrical. PPC Brief, WP-02-B-PP-01, at 38.

BPA's Position

The minimum charge is five mills/kWh. This will be the minimum charge for both HLH and LLH Within-Month Excess Factoring energy. Keep *et al.*, WP-02-E-BPA-17, at 23. Also, this amount (5 mills) sets a floor to ensure that there is some minimum penalty for Within-Day Factoring. *Id.* at 22.

Evaluation of Positions

BPA notes that prudent reliability is best served by an unambiguous and substantial price signal associated with exceeding product service, such that customers will have an incentive to purchase the appropriate products in advance. Keep *et al.*, WP-02-E-BPA-17, at 22; Tr. 1214. It is BPA's intent to establish the appropriate penalties such that parties will not ignore the products BPA makes available to support customer resources and avoid excess factoring and unauthorized increases. *Id*.

In its analysis of the UAI Charge, PPC asserts that BPA's UAI Charge design is asymmetrical given that it includes floor charges in conjunction with market-based charges. PPC Brief, WP-02-B-PP-01, at 37. PPC further argues that if BPA levies market-based charges during periods of high market prices, it should similarly charge market prices when those prices are low. *Id.* PPC witnesses argue that BPA should collect only the costs that it incurs. Opatrny *et al*., WP-02-E-PP-02, at 23. PPC asserts that BPA should not realize a windfall from unauthorized increases when market prices are low: "if BPA is going to rely on market indexes for determining the extent to which it is harmed, then a floor is unnecessary." *Id.*

In response to the PPC's analysis as applied to the Excess Factoring Charge, BPA maintains that the five mills/kWh floor is appropriate to assure that there will always be some penalty to deter customers from placing an excess factoring burden on BPA's system. Keep *et al.*, WP-02-E-BPA-17, at 23. BPA incorporates the following arguments regarding UAI Charges since they are applicable to excess factoring as well. PPC's argument that BPA should collect only the costs that it incurs ignores the need for a meaningful penalty component that deters customers from placing unauthorized increases on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 33. Similarly, the Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specified limits and, secondarily, to protect BPA from cost exposure in those instances where Excess Factoring does occur.

Keep *et al.*, WP-02-E-BPA-17, at 22. The Excess Factoring Charge operates similar to the UAI Charge, and is intended to be a penalty rather than a cost recovery mechanism. Keep *et al.*, WP-02-E-BPA-43, at 34. While protection against BPA's cost exposure is a consideration in the design of the UAI Charges and the Excess Factoring Charge, the penalty aspect in the charges is necessary to motivate customers to purchase the products and services to ensure that they do not place loads on BPA beyond their contractual rights, and not to use unauthorized increases or excess factoring services as an economical alternative to those products and services. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 28-29; Tr. 1213-14. BPA's ability to plan its service obligations for the core Subscription products and to control its costs depends on customers accurately specifying the obligations that BPA must serve. Keep *et al.*, WP-02-E-BPA-17, at 17. Therefore, just as described in the case for the UAI Charges, any occurrences of excess factoring undermine BPA's ability to plan its service obligations and control its costs. In addition, the five mills/kWh floor is appropriate to ensure that there is some minimum penalty for Within-Day Excess Factoring in the event that the hourly index does not yield a higher charge or, although less likely, that at some point during the rate period there is no suitable hourly index available. Keep *et al.*, WP-02-E-BPA-17, at 22. In initial testimony concerning Within-Month Excess Factoring, BPA stated: "The five mills/kWh floor is appropriate to assure that there will always be some penalty to deter customers from placing this Excess Factoring burden on BPA's system." *Id.* at 23.

Further, the minimum charges may be necessary to ensure that the penalty charges are high enough to provide a meaningful deterrent. Though BPA did not find any historical instances where the floor charge would have been applied, the minimum charges are necessary to ensure that the penalty component is in place during all periods sufficient to deter customers from placing excess factoring on BPA's system. *Id*.

Decision

BPA's floor component for the Excess Factoring Charge is necessary to preserve the deterrent nature of the charges, and to preserve customer incentives to plan and operate their systems in a fashion that avoids the occurrences of excess factoring.

Issue 4

Whether in the rate case BPA should create an exemption from Excess Factoring Charges for excess factoring events related to customer forecast error.

Parties' Positions

SUB argues that it is wrong to apply Excess Factoring Charges in the event of customer load variations, because II.B.1 of the Subscription ROD states that load variations are part of a core, cost-based product. SUB Brief, WP-02-B-SP-01, at 9. SUB states that "BPA's suggestion to purchase a FPS product to meet load forecast error is also inconsistent with the Subscription ROD." *Id*. SUB further contends that "BPA's rate design is flawed in that it does not comport with the Subscription ROD guidelines." *Id*. SUB contends that "[b]ecause the Federal Register Notice states that issues, such as the definition of a Core Subscription Product, decided in the

Subscription ROD are not able to be revisited in this case and the fact that BPA has created a product which does not comport with the Subscription ROD, variation in load is a rate case issue." SUB Ex. Brief, WP-02-R-SP-01, at 11.

BPA's Position

BPA offered an FPS-priced product to meet load forecast error. Case-specific FPS-priced resource variability products could be negotiated to replace Excess Factoring Charges for forecast error. Keep *et al.*, WP-02-E-BPA-43, at 35. SUB contends that this FPS-priced product is also in conflict with section II.B.1 of the Subscription ROD. This is a new issue raised in answer to BPA's FPS offering.

Evaluation of Positions

SUB argues that BPA's rate design is flawed because of an alleged inconsistency between Section II.B.1 of the Subscription ROD and BPA's suggestion that customers purchase an FPS product to meet load forecast error. SUB Brief, WP-02-B-SP-01, at 9. SUB points to BPA's rebuttal testimony as evidence of this flaw, where BPA states: "Because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges." *Id*., quoting Keep *et al*., WP-02-E-BPA-43, at 35. SUB's brief criticizes the factoring service in the Actual Partial Service-Complex product, not the proposed Excess Factoring Charge. *Id*. SUB argues that BPA has created a product which does not comport with the Subscription ROD, and thus variation in load is a rate case issue. SUB Ex. Brief, WP-02-R-SP-01, at 11. SUB notes that in its testimony it suggested modifying the proposed Excess Factoring Rate in an attempt to align the rate with the Subscription ROD. *Id*.

In its brief on exceptions, SUB continues to mischaracterize Load Forecast Error as a load variation rather than as an inability to accurately forecast load. BPA does not agree with SUB's characterization. SUB has offered no reason for BPA to alter its position. SUB's argument regarding the Excess Factoring Charge is intertwined with BPA's power product development. In its comments regarding the factoring service, SUB expresses its confusion over the product and questions whether the rate can be successfully implemented as a result of errors SUB claims have been made in attempts to clarify application of the rates associated with factoring. *Id*. SUB alleges there is low customer confidence in the product and raises the issue of whether the rate design for factoring and associated products has been proposed according to "sound business principles." *Id*. The appropriateness of the excess factoring service to events involving customer load variations, however, is a function of product design, and therefore is not a rate case issue.

BPA testified that factoring service is a bundled component of Subscription core products for Full Service and Actual Partial Service. Keep *et al*., WP-02-E-BPA-17, at 19. By definition, a customer without resources or a customer whose resources are delivered flat will take exactly the amount of factoring service that they are entitled to. *Id*. In comparison, BPA testified further that for purposes of administering the Actual Partial Service-Complex product, which involves serving customers with variable resources, a factoring benchmark test would be done in the billing process. *Id*. Factoring, subject to the benchmark process, may be purchased as an add-on to a Firm Block core product. *Id*. SUB mischaracterizes the way customer load variations would interact with the product provisions for purposes of determining excess factoring usage. SUB's witness argued against the factoring service because "BPA's proposed factoring service is an unbundled service from what BPA is currently offering and would increase the cost of doing business with BPA in purchasing an Actual Partial Service product." Nelson, WP-02-E-SP-01, at 9. SUB noted that BPA's PF service currently follows both customers' loads and customers' resources. *Id*. SUB's mischaracterization of load forecast error as load variation is an inappropriate attempt to derail the unbundled factoring service.

BPA testified that the rates applicable to BPA's core Subscription products assume that BPA undertakes the cost of factoring energy to meet the shape of customer loads, but not the various potential shapes of customer resource generation. Keep *et al*., WP-02-E-BPA-17, at 22. BPA testified that excess factoring can be defined generically as that amount of factoring service (energy distributed among hours to match a load shape), measured in kWh, which is outside the factoring benchmarks. *Id*. at 20. Incurring excess factoring results from the lack of a corresponding change in the customer's resource amounts, not from load variation. "Only when customer resources have hour-to-hour variability is there a possibility of receiving factoring service amounts which are less or greater than the entitlement amount." *Id*. at 19-20. SUB's witness contends that situations outside the customer's control (such as retail outages or weather forecast error) could cause Excess Factoring Charges to occur. Nelson, WP-02-E-SP-01, at 11. BPA agrees. An error in forecasting that causes a customer to apply its resources in a shape that is outside the factoring benchmarks--anywhere between flat and following actual and complete load shape--could trigger excess factoring charges. *See* Keep *et al*., WP-02-E-BPA-17, at 20. Therefore, when the customer applies its resources counter to its load shape, BPA's factoring service could be forced outside of the benchmarks established in the basic product. *Id*. SUB errs in its analysis by attributing this variation in take from BPA, which is outside the benchmarks of the basic product, to load variation. In the circumstances described by SUB, the additional variation is caused by the customer's inability to forecast its loads accurately enough to stay within the bounds of the basic product.

BPA notes that it responded to the concern raised by SUB regarding forecast error and the Excess Factoring Charge. Because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges. Keep *et al*., WP-02-E-BPA-43, at 35. Since BPA will not be able to separate excess factoring that was due to circumstances outside the customer's control from those within the customer's control, all are treated as excess factoring in the basic product. *Id*. Different customer load resource situations could greatly influence the significance of load forecast error, but these cannot be addressed generically. *Id*. Case-specific FPS-priced resource variability products could be negotiated to replace Excess Factoring Charges for forecast error. *Id*. This is consistent with BPA's testimony that BPA is willing to "offer a limited amount of excess factoring service through a resource variability product priced under the FPS rate schedule to customers purchasing the complex partial product . . . However, this is a product and contract issue rather than a rate case issue." *Id*. at 34.

Decision

In the rate case BPA has not created an exemption from Excess Factoring Charges for excess factoring events related to customer forecast error. BPA will negotiate customer-specific flexibilities outside the scope of the rate case in Subscription contract negotiations.

Issue 5

Whether BPA should reduce within-day Excess Factoring Charges to correspond to reductions for within-month factoring when the customer experiences UAI Energy Charges.

Parties' Positions

PPC argues that BPA should make a reduction for within-day factoring to correspond with BPA's proposal to reduce within-month factoring quantities by any unauthorized increase energy amounts for the comparable diurnal period. PPC Brief, WP-02-B-PP-01, at 38.

BPA's Position

Because there is a possibility that some combination of factors on a customer's system could trigger UAI Charges and Excess Factoring Charges simultaneously, BPA will allow mitigation or avoidance of such charges. Keep *et al.*, WP-02-E-BPA-17, at 24. The amount of energy subject to the Within-Month Excess Factoring Charges will be reduced by the amount of energy which is levied the UAI Charge for energy in the same diurnal period. *Id*. at 25.

Evaluation of Positions

PPC noted that BPA proposes to reduce within-month factoring quantities by any UAI Energy amounts for the comparable diurnal period. PPC Brief, WP-02-B-PP-01, at 38. PPC contends that BPA should make a corresponding reduction for within-day factoring. *Id*. PPC presented no rationale for this offset, except to note that BPA did such an offset for within-month factoring.

BPA proposed a level of mitigation that it determined was reasonable, that being the reduction of Excess Within-Month Factoring by any UAI Charge for energy in the same diurnal period. Keep *et al*, WP-02-E-BPA-17, at 25. Within-month factoring deals with the quantity of energy delivered: "Those boundaries represent a take from BPA that falls between flat and meeting all of the customer's load variations for the period." Keep *et al.*, WP-02-E-BPA-17, at 21. The GRSPs provide that the within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 93. Since both unauthorized increase energy and excess within-month factoring deal with the quantity of energy delivered, there is a clear correlation between the two penalties. That, coupled with the likelihood (though not certainty) that an UAI Energy Charge event would result in an Excess Within-Month Factoring Charge, led BPA to mitigate the penalty charges. *Id*. at 24.

The GRSPs include an adjustment to the amount of energy subject to Excess Factoring Charges when a customer incurs both an UAI Charge for energy and a Within-Month Excess Factoring

Charge. Keep *et al.*, WP-02-E-BPA-17, at 25. Specifically, the amount of energy subject to the Within-Month Excess Factoring Charges will be reduced by the amount of energy which is levied the UAI Charge for energy in the same diurnal period. *Id*.

The intent of the penalty charges is to provide customers with a sufficient incentive to avoid placing unauthorized increases and excess factoring on BPA. *Id*. Without this mitigation to the Excess Factoring Charges, the collective penalty amounts would go beyond BPA's intent. *Id*.

Unlike within-month factoring, BPA's excess within-day factoring is not a quantity test. Nor is there a direct or constant correlation between unauthorized increase energy and excess within-day factoring. Within-day factoring places no boundaries on the amount of energy taken from BPA. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 92-93. When within-day factoring has occurred, BPA has in effect provided a shaping service associated with the customer's resources rather than its load. Keep *et al.*, WP-02-E-BPA-17, at 22. BPA has testified that the customer's hour-by-hour energy take from BPA is compared to the average energy take in the same period. *Id*. at 20. This average energy amount can be any amount from no energy to the customer's entire system load without triggering the Excess Within-Day Factoring Charge. Since the within-day factoring test is a test of shape rather than quantity, BPA does not agree that UAI Energy charges should offset Excess Within-Day Factoring Charges.

Because within-day factoring is not assessed based on the amount of energy taken in a day, there is no direct and constant correlation between unauthorized increase energy and excess within-day factoring. Therefore, UAI Energy Charges will not offset excess within-day factoring charges.

<u>Decision</u>

BPA will not reduce Within-Day Excess Factoring Charges to correspond to reductions for within-month factoring when the customer also experiences UAI Energy Charges.

<u>Issue 6</u>

Whether BPA's factoring charges expose customers to substantial retroactive penalty.

<u>Parties' Positions</u>

OURCA argues that the Excess Factoring Charge is unreasonable because it imposes a penalty that is retroactive. OURCA Brief, WP-02-B-OU-01, at 7. OURCA reiterates this argument in its brief on exceptions. OURCA Ex. Brief, WP-02-B-OU-01, at 6.

<u>BPA's Position</u>

The Excess Factoring Charges would apply only to products that customers may choose to subscribe to in the future under BPA's Subscription process. Burns *et al.*, WP-02-E-BPA-08, at 8-9. Excess Factoring Charges will be applied in the BPA billing process. Keep *et al.*, WP-02-E-BPA-17, at 19.

Evaluation of Positions

OURCA cites *Allegheny Power System*, 85 F.E.R.C. ¶ 61,370 (1998) to support the proposition that penalties are unreasonable if they are retroactive, because they serve no practical deterrent. OURCA Brief, WP-02-B-OU-01, at 7. OURCA argues that BPA admits that the Within-Day Charge may expose customers to a substantial retroactive penalty because of inadvertent load forecast. *Id*., citing Keep *et al*., WP-02-E-BPA-43, at 35. OURCA believes that these charges should be eliminated or revised. *Id*.

OURCA's reliance on the *Allegheny Power System* case is misplaced and fails to support OURCA's proposition. In that case, FERC found that, in filing revisions to its open access *pro forma* transmission tariff, Allegheny Power's proposed revisions might have allowed Allegheny Power to charge undefined and possibly retroactive penalties. 85 F.E.R.C. ¶ 61,370, 62,415. Although FERC ordered Allegheny Power to remove such provisions, FERC stated that Allegheny was free in a new proceeding to propose and support additional, specific penalties that Allegheny believes are necessary. *Id*. Similarly, BPA proposed on a prospective basis a charge that applies in the event customers exceed their contracted-for amounts of service. Keep *et al*., WP-02-E-BPA-43, at 34. In addition, because BPA recognizes there could be situations in which load forecast error occurs, BPA is offering additional products to replace excess factoring for forecast error. *Id*. at 35. OURCA claims that BPA admits that the Within-Day Factoring Charge may expose customers to a substantial retroactive penalty because of inadvertent load forecast error. OURCA Brief, WP-02-B-OU-01, at 7. Despite OURCA's claim, the record clearly shows that BPA testified that because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges. Keep *et al*., WP-02-E-BPA-43, at 35. Since BPA will not be able to separate excess factoring that was due to circumstances outside the customer's control from those within the customer's control, all are treated as excess factoring in the basic product. *Id*. Different customer load and resource situations could greatly influence the significance of load forecast error, but these cannot be addressed generically. *Id*. Case-specific FPS-priced resource variability products could be negotiated to replace excess factoring charges for forecast error. *Id*.

Decision

BPA's factoring charges do not expose customers to retroactive penalties. To account for load forecast error, BPA will offer case-specific FPS-priced resource variability products to replace Excess Factoring Charges for forecast error.

Issue 7

Whether the Excess Factoring Charge should exempt from its calculations load swings caused by cogeneration and renewable resources over which the utility customer does not exercise control, and which are not the result of power marketing activities.

Parties' Positions

WPAG argues that imposing the Excess Factoring Charge on cogeneration and renewable resources, without recognition of their unique operating characteristics, is bad public policy. WPAG Brief, WP-02-B-WA-01, at 22. WPAG contends that the Excess Factoring Charge as currently formulated will discourage the development of cogeneration and renewable resources by utility customers, and unfairly impose a penalty on those who have already developed such resources. *Id*. at 23.

BPA's Position

The Subscription Strategy is BPA's approach to marketing Federal power for the period FY 2002-2006. Burns *et al*., WP-02-E-BPA-08, at 6. The Strategy addresses the availability and marketing of power, describes power products, lays out strategies for pricing, including risk management, and discusses contract elements. *Id*. at 7. BPA's product designs for Subscription core products were adopted in the Subscription Strategy ROD, and the decisions contained in that document are not at issue in this rate case. *Id*. A goal of the Subscription Strategy is to provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies. *Id*. The Subscription product provisions for the Generation Management Services product recognize that some resources could qualify for treatment, referred to as measured amount netting, which is similar to that suggested by WPAG. *See* BPA Power Products Catalog, December 1999, at 56-58. Also, in the resource declaration parameters of the Actual Partial Service-Complex product, point 4 states "If the customer acquires new renewable resources *for which it wishes to declare a firm capability*," indicating that such resources will not be required by BPA to have declared firm capabilities. (Emphasis added.)

Evaluation of Positions

WPAG is concerned about application of the Excess Factoring Charge to renewable and cogeneration resources over which the customer has little or no control, and the output of which varies based on factors unrelated to market decisions. WPAG Brief, WP-02-B-WA-01, at 22. Although WPAG points out a potential problem with the application of the Excess Factoring Charge, WPAG does not indicate why a rate exemption would be necessary or more appropriate than the measures adopted under the Subscription Strategy and Power Products catalog. Those measures allow for resource-specific treatment that is consistent with BPA's policies. A blanket exemption for resources by generation type, *i.e*., cogeneration or renewable, might have effects beyond those intended under the policy objectives BPA adopted in the Subscription Strategy.

Decision

While BPA agrees with the premise, BPA will continue with its strategy to address the appropriate treatment of cogeneration and renewable resources outside the scope of the rate case within customer-specific Subscription contract negotiations.

10.8 Applicable Rate for Pre-Subscription Contracts that have Collared Price Provisions

Some Pre-Subscription contracts include price provisions that base the contract price on the lowest cost-based rate that goes into effect on October 1, or the successor of the PF-96 rate, as established in this current power rate proceeding. Keep *et al*., WP-02-E-BPA-17, at 26. These price provisions include collars, such that if the price for the contract or a specified test price, as based on the final PF-02 rate, exceeds the collar, the contract price is then equal to or based on the upper collar. *Id.* If that same calculation is below the lower collar, then the price for power sold under such contracts is equal to, or based on, the lower collar. *Id*. The prices in collared Pre-Subscription contracts are to be calculated based on the lowest cost-based rate that goes into effect on October 1, 2001, or the successor to the PF-96 rate. *Id.* For the purposes of determining the appropriate charge for the Pre-Subscription contracts, BPA will use the five-year average rate. *Id.* Pre-Subscription contracts provide that the contract price be established once and only once after the final PF-02 rates are published. *Id.* Establishment of the five-year average rate applicable to pre-Subscription contracts is consistent with BPA's Power Subscription Policy ROD at 120. *Id.* Because no party raised the issue of the applicable rate for pre-Subscription contracts that have collared price provisions, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3, 51 Fed. Reg. 7611 (1986).

10.9 Stepped-Up Multiyear Block Charge (SUMY)

The SUMY Block Charge applies to Block purchases if annual amounts specified at the outset of contractual commitment increase (*i.e.* step-up) over multiple years of a purchase commitment term due to projected increases in customer net requirements which are not subject to a TAC. Keep *et al.*, WP-02-E-BPA-17, at 10. BPA's Subscription core product description for the Block product defines the maximum annual purchase amount as an amount equal to the customer's annual net requirement for each year of the term of commitment as established at the time of commitment. *Id*. The SUMY Block Charge provides BPA with cost coverage to meet these established changes in net requirements for subsequent purchase years. *Id*. The charge is associated with a Block purchase, which steps up over its multiyear term, and may be applicable to the basic Block purchase even if the purchaser also selects to purchase an add-on product such as Factoring or Shaping Capacity. *Id*. at 12. The charge is applied to the total multiyear Block energy purchase amount, including the stepped-up amounts. *Id*. at 11-12.

Block increase amounts will be determined during the Subscription window and fixed by BPA and the customer prior to the signing of the contract. *See* section 2.3.5.2, Wholesale Power Rate Development Study, WP-02-E-BPA-05. The SUMY Block Charge will be applied when amounts for any year, month, or monthly HLH and LLH periods of a multi-year declared Block purchase are greater than the first year's amount. *Id*. These additional purchase amounts will be assumed by BPA to be purchased at market prices. *Id*. The charge for these increased purchase amounts will be the difference between PF rates and the AURORA monthly on and offpeak market price forecast. *Id*. The pricing methodology approximates the incremental cost BPA must bear in providing the SUMY Block. *Id*. The charge will be computed for each customer based on its increasing Block profile. It will equal the total cost of the SUMY Block service divided by the total Block energy purchase including stepped-up amounts. The charge will be applied to the entire Block purchase and be in addition to the PF or NR energy and demand rates that the customer will pay for these power purchases. Keep *et al.*, WP-02-E-BPA-17, at 12-13. The formula for calculating the charge is described in the Wholesale Power Rate Schedules under the Adjustments, Charges, and Special Rate Provisions section. *See* Wholesale Power Rate Schedules, Appendix 1, WP-02-A-02, Section II.S.

Issue 1

Whether the proposed SUMY Charge should be eliminated.

Parties' Positions

PPC argues that the proposed SUMY Block Charge should be eliminated because it recovers market prices for services which should be cost-based pursuant to BPA's statutory ratemaking directives. PPC Brief, WP-02-B-PP-01, at 32-34; PPC Ex. Brief, WP-02-R-PP-01, at 7. Further, PPC claims, the SUMY is unnecessary due to BPA's advance knowledge of a customer's net requirements for the term of the contract. PPC Brief, WP-02-B-PP-01, at 34. OURCA adopts and joins the PPC's recommendation to eliminate the SUMY Block Charge. OURCA Brief, WP-02-B-OU-01, at 7-8; OURCA Ex. Brief, WP-02-R-OU-01, at 4. ICNU argues the SUMY charge creates an egregious form of discrimination and that BPA could plan to meet these loads now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-02, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10-11.

BPA's Position

BPA has established that eliminating the SUMY Block Charge would lead to an underrecovery of BPA's costs associated with the cost of increasing the FBS to serve increasing load. Keep *et al*., WP-02-E-BPA-43, at 20. Under the SUMY Block Charge, BPA is estimating the cost of increasing the FBS to be the cost of purchasing power at the market prices forecast by AURORA. *Id*. Therefore, the SUMY Block Charge ensures BPA's ability to capture all costs associated with serving load placed on BPA by customers purchasing stepped-up blocks of power.

Evaluation of Positions

PPC argues that because of certain factors, the SUMY Block Charge should be eliminated. PPC Brief, WP-02-B-PP-01 at 32. PPC argues that loads will be known by September 30, 2000, the close of the Subscription window. *Id.* Such PF load is "expected" as that term has been used in the imposition of the TAC. *Id*. PPC incorporates the load/resource balance analysis it made with respect to BPA's load/resource balance analysis described in the TAC section. *Id*. PPC alleges that BPA's expectations of resource deficit are not on solid foundation, given deficiencies in BPA's load/resource balance analysis, its disinclination to recall surplus sales, and its policy decisions to serve non-preference customers. *Id*. ICNU suggests that BPA could plan to meet the load now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-02, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10.

BPA agrees that the SUMY Block amounts will be known in advance. However, even with advance knowledge of customers' net requirements, BPA still incurs costs for serving this stepped-up load due to the costs that will be incurred to increase the FBS. Keep *et al.*, WP-02-E-BPA-43, at 22. The Load Variance Charge does not apply to sales of Block power. Keep *et al*., WP-02-E-BPA-17, at 8. The SUMY Block Charge, therefore, provides BPA with cost coverage to meet these established changes in net requirements for subsequent purchase years. *Id*. at 10. It provides BPA the same type of load growth coverage for the Block product, and thus recovery of costs, that the Load Variance Charge recovers from the Full and Partial Requirements products.

The Load Variance Charge covers the load growth costs associated with Full and Actual Partial Service. Keep *et al*., WP-02-E-BPA-43, at 22. Load growth for customers purchasing Full and Actual Partial Service is estimated, and costs to serve are unknown. *Id*. In comparison, the SUMY Block purchaser pays for its increase in net requirements through the SUMY Block Charge. *Id*. The increase in the stepped-up amount of the Block power may be due to any increase in net requirements. *Id*. Simply because the purchase of the amount of the Block is known in advance does not minimize or reduce BPA's need for the SUMY Block Charge. Without the SUMY Block Charge, BPA risks underrecovering its costs and revenues, because customers purchasing the stepped-up Block will not be paying the costs BPA will incur to serve the load growth component.

The load growth component of the Load Variance Charge is estimated based on forecast loads and is not take-or-pay on a predetermined amount, but instead on actual net requirements. Keep *et al*., WP-02-E-BPA-17, at 11. The load growth component of the SUMY Block Charge will not be known until time of contract signing. *Id.* ICNU suggests that BPA could plan to meet SUMY Block loads now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-01, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10. ICNU argues that approach is consistent with BPA's statutory obligations to provide the firm net requirements of preference customers "whenever requested." ICNU Ex. Brief, WP-02-R-IN-01, at 10, citing 16 U.S.C. §839c(b)(1). It is important to recognize that BPA acknowledges it has an obligation to meet the net requirements of its preference customers with the FBS and replacements thereto. Keep *et al*., WP-02-E-BPA-43, at 22. The language "whenever requested" in section 5(b)(1) of the Northwest Power Act refers to BPA's offer of a power sales contract to its utility customers. Once a contract is executed under section 5(b)(1), BPA will serve load thereunder in accordance with the terms of the contract, at the applicable rates then in effect. The Load Variance Charge is based on forecast loads, but BPA is not forecasting any SUMY Block load. There are no SUMY Block loads for estimating a charge nor any purchase class in which to spread the charge; therefore, no revenue reductions to the revenue requirement are assumed from SUMY Block loads. The only reductions to the revenue requirement for energy are the capacity and load variance components of electric power. *See* section 3.2.3, Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 52. Revenues from all other components of sales are assumed to equal costs, and therefore they would not have any further impact on net revenue requirement. When the SUMY Block purchase becomes known, then "BPA can purchase SUMY Block amounts in advance any time before they are needed." Keep *et al*., WP-02-E-17, at 11. Without the imposition of the SUMY Block Charge, the costs associated with serving the load growth component of the increased Block would not be recovered. Under the SUMY Block Charge, BPA is estimating the cost of increasing the FBS to be the cost of purchasing power at the market prices forecast by AURORA. *Id*. at 20.

PPC argues that BPA's expectations of resource deficits are not on solid foundation. PPC Brief, WP-02-B-PP-01, at 33. To support its claim, PPC argues two points: first, there are deficiencies in BPA's load/resource balance analysis and second, BPA is disinclined to recall surplus sales and has made policy decisions to serve nonpreference customers. *Id*. These arguments are addressed by BPA in the TAC section of this ROD, section 10.15.

PPC's next example points to BPA's decision to serve nonpreference customers. PPC contends that BPA is disinclined to recall surplus sales and has made policy decisions to serve nonpreference customers. PPC Brief, WP-02-B-PP-01, at 33; PPC Ex. Brief, WP-02-R-PP-01, at 7. As shown by BPA in response to similar legal issues raised by PPC in section 10.15 on the TAC, BPA has clear legal authority to make sales to nonpreference customers. Such sales are not prohibited in order to reduce the cost of power to public agency customers. *See* Burns and Elizalde, WP-02-E-BPA-37, at 4.

<u>Decision</u>

BPA will not eliminate the SUMY Block Charge, because it is needed to recover costs associated with meeting load growth under the multiyear stepped-up Block purchase.

<u>Issue 2</u>

Whether the method for computing the SUMY Block Charge is cost-based and in accord with BPA's ratemaking directive to set cost-based rates.

<u>Parties' Positions</u>

PPC and OURCA argue that the SUMY Block Charge is not cost-based as it should be, pursuant to BPA's statutory ratemaking directives. PPC Brief, WP-02-B-PP-01, at 32-34; PPC Ex. Brief, WP-02-R-PP-01, at 7; OURCA Brief, WP-02-B-OU-01, at 7-8; OURCA Ex. Brief, WP-02-B-OU-01, at 7.

ICNU argues that the SUMY Block Charge is "an attempt to charge market-based rates for load growth which BPA should provide from Federal Base System resources . . ." ICNU Ex. Brief, WP-02-R-IN-01, at 11.

<u>BPA's Position</u>

The SUMY Block Charge is cost based, as BPA anticipates that it will be purchasing in the market to cover the cost of increasing the FBS for the stepped up Block amounts. Tr. 1189-1190. The estimated cost is the market prices forecast by AURORA. Keep *et al.*, WP-02-E-BPA-43, at 22.

Evaluation of Positions

PPC argues that the SUMY Block Charge should be cost-based and that the method proposed is not cost-based. PPC Brief, WP-02-B-PP-01, at 32. PPC claims that determining the proposed SUMY Block Charge using market-based prices violates BPA's statutory ratesetting directive for implementation of cost-based rates. *Id*.

BPA testified that the SUMY Block Charge is cost-based, as BPA's forecast of its loads and resources shows that it will be necessary for BPA to purchase in the market to serve such increases in Block loads. Keep *et al*., WP-02-E-BPA-17, at 12-13; Keep *et al*., WP-02-E-BPA-43, at 22; Tr. 1191-1192. BPA also acknowledges its obligation to meet the net requirements of its preference customers with FBS and replacements thereto, and when it does so, BPA must recover its costs. Keep *et al*., WP-02-E-BPA-43, at 20.

PPC's argument that the SUMY Block Charge is not cost-based appears to reflect the position that any power that BPA purchases from the market to serve preference agency customer load is not cost-based pursuant to section 7(b)(1) of the Northwest Power Act. 16 U.S.C. §839e(b)(1). ICNU shares a similar position and argues that if the FBS is not sufficient to meet these requirements, BPA should augment or supplement the FBS, or add replacement resources, and it should meld in those costs with other PF costs. ICNU Ex. Brief, WP-02-R-IN-01, at 11. Contrary to PPC's and ICNU's contention, however, the SUMY Block Charge is a cost-based charge. Tr. 1189, 1190. Power purchased to meet the stepped-up load that is subject to the SUMY Block Charge is FBS replacement power, Keep *et al*., WP-02-E-BPA-43, at 20; Tr. 1189, 1190; the cost of which must be recovered consistent with section 7 of the Northwest Power Act. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's costs included in the SUMY Block Charge to replace reductions in the capability of the FBS resources constitute the costs of FBS resources. Under section 7(e), BPA has broad authority to design its rates to recover its total costs to meet its revenue requirement. To meet the cost of load growth under the stepped-up Block, an adjustment charge such as the SUMY Block Charge is appropriate. 16 U.S.C. §839e(e). "In short, the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364 (9th Cir. 1987).

Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal, or other rate forms.

16 U.S.C. §839e(e).

BPA's rates are "cost-based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. Nevertheless, within the context of those directives, section 7(e) and its legislative history make clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Congress did not direct BPA to use specific rate structures or billing practices to show the cost of new power supplies. As a result, it was recognized that many provisions could lead to rate reforms. *See*, *e.g., Comptroller General of the United States, Comments on Pacific Northwest Power Planning and Conservation Act* - H.R. 8157, reprinted in Cong. Rec. H 10687 (November 17, 1980).

Decision

The method for computing the SUMY Block Charge is cost-based and is in accord with BPA's statutory ratemaking directives

Issue 3

Whether the SUMY Block Charge is comparably priced for the equivalent service provided under the Load Variance Charge for meeting load growth.

Parties' Positions

PPC claims that the SUMY Block Charge is not comparably priced, as it provides an equivalent service to the service provided to purchasers of Full and Partial requirements service, but at a much higher price. PPC Brief, WP-02-B-PP-01, at 32-34.

BPA's Position

The two different methods for allocating load growth costs to the Load Variance Charge and SUMY Block Charge are appropriate. Keep *et al.*, WP-02-E-BPA-43, at 22. The Load Variance Charge covers for load growth costs associated with Full and Actual Partial Service using option pricing, which includes a risk premium because load growth is estimated and unknown. *Id*. The SUMY Block Charge covers for load growth costs using the AURORA market forecast, which does not include a risk premium because stepped-up amounts are known in advance. *Id*.

Evaluation of Positions

PPC argues that the SUMY as designed fails BPA's own rate objective to provide an equivalent service that is provided to purchasers of Full and Partial requirements service through the Load Variance Charge. PPC Brief, WP-02-B-PP-01, at 33. PPC concludes that the proposed pricing differential defies logic. *Id*. PPC claims that they are not remotely comparable because the SUMY Block Charge is approximately one mill greater than the 0.8 mill Load Variance Charge. *Id*.

PPC's conclusion that the SUMY Block Charge and Load Variance Charge are not comparable is based upon assumptions provided by PPC to BPA to calculate the pricing differential that resulted in the disparity. PPC references BPA rebuttal testimony, where a SUMY Block Charge is calculated at 2.23 mills/kWh, and compares this amount to the Load Variance Charge of 0.8 mills/kWh and concludes that the two charges are not comparable. PPC Brief, WP-02-B-PP-01. PPC's charge comparison fails to account for the different amounts of load growth assumed in building each charge. The SUMY Block Charge example referenced by the PPC (referencing BPA rebuttal, WP-02-E-BPA-43, at 21) is based upon assumptions the PPC submitted to BPA that defined the levels for which BPA made its comparison. PPC requested that BPA use a load growth increase amount of 10 percent. The Load Variance Charge used a load growth of approximately 1.2 percent. The 1.2 percent was never actually stated in testimony as a percent, but instead was referred to as being the load growth reflected in the NWPPC's forecast of public and Federal agencies' TRL. *See* Loads and Resources Study, WP-02-E-BPA-01, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A. The calculation of the Load Variance Charge in Volume 2, section 4.1, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, section 4.1, shows TRL both with and without load growth; the load growth of approximately 1.2 percent can be calculated from these amounts. The 2.23 mills/kWh charge was determined using the 10 percent stepped-up amount scenario as requested by the PPC. Had PPC requested the same 1.2 percent stepped-up amounts for its SUMY Block purchase scenario as was used for load growth in the Load Variance Charge, the SUMY Block Charge would have resulted in a charge of 0.31 mills/kWh. This lower charge for SUMY, given the same assumption for load growth, is appropriate, because the SUMY charge does not include a risk premium. Keep *et al*., WP-02-E-BPA-43, at 22. PPC has no reasonable evidence to support its claim that BPA's SUMY Block Charge pricing differential defies logic or that it results in noncomparable charges.

Decision

The SUMY Block Charge is comparably priced for the equivalent service provided under the Load Variance Charge for meeting load growth.

Issue 4

Whether applying the SUMY Block Charge to the entire PF Block purchase amount is appropriate.

Parties' Positions

PPC and OURCA argue that the SUMY Block Charge should be applied only to the stepped-up amounts and not to the entire Block purchase amount. PPC Brief, WP-02-B-PP-01, at 32; OURCA Brief, WP-02-B-OU-01, at 8; OURCA Ex. Brief, WP-02-R-OU-01, at 7.

BPA's Position

Applying the SUMY Block Charge to the entire Block purchase amount is consistent with BPA's proposal to bill all load at a posted rate. Keep *et al.*, WP-02-E-BPA-17, at 11; Keep *et al*., WP-02-E-BPA-43, at 23.

Evaluation of Positions

PPC and OURCA argue that they do not understand why BPA applies the SUMY Block Charge to the entire Block purchase and not just the incremental purchase. PPC Brief, WP-02-B-PP-01, at 32; OURCA Brief, WP-02-B-OU-01, at 8; OURCA Ex. Brief, WP-02-R-OU-01, at 7; Opatrny *et al.*, WP-02-E-PP-02, at 18.

BPA proposed to apply the SUMY Block Charge to the entire Block purchase because it is an efficient and simple billing method, which results in a charge that allows BPA to bill on total kWh sold rather than bill on different kWh amounts in different years. Keep *et al.*, WP-02-E-BPA-17, at 11; Keep *et al*., WP-02-E-BPA-43, at 23; Tr. 1193. The charge is developed using only the stepped-up amounts. *Id.* It is then spread across and charged to all kWh, including the stepped-up amounts. *Id*. The charge for the stepped-up amounts could have been billed on only the stepped-up amounts in a number of different ways; *e.g*., charged separately for each monthly diurnal period, for each separate month, for each yearly diurnal period, or for each separate year. Regardless of the billing method chosen, the resulting customer bill would be no different under any one of the scenarios than it would be by spreading the total cost of the stepped-up amounts over all Block amounts. Parties have not provided argument for why charging the cost to only the stepped up amounts is a superior method.

Decision

It is appropriate to apply the SUMY Block Charge to the entire PF Block purchase amount.

10.10 Flexible Rate Options

10.10.1 Flexible Priority Firm Power (PF) and New Resource Firm Power (NR) Rate Options

Issue

Whether BPA should continue to offer optional flexible demand and energy charges within the PF and NR rate schedules.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed to continue the Flexible PF and NR rates in order to provide BPA a flexible marketing tool. Gustafson and Thompson, WP-02-E-BPA-23, at 7-9.

Evaluation of Positions

The Flexible PF and NR rates provide BPA a useful marketing tool. Gustafson and Thompson, WP-02-E-BPA-23, at 7. While these rates ensure that BPA receives the same revenues on a net present value (NPV) basis that BPA would have received under the posted rates, the flexible rates allow BPA to structure payments to better meet customers' needs. *Id.* For example, BPA's ability to compete will be improved if it can offer a five-year Block sale of power, at 100 percent load factor, take-or-pay, at a single rate expressed in mills/kWh. BPA might otherwise be placed at a competitive disadvantage with some customers if it could offer only the more complex pricing embodied in the PF and NR rate schedules with their different seasonal and diurnal energy charges and a separate demand charge. *Id.* The Flexible PF and NR rates will be offered at BPA's discretion to PF Preference and NR purchasers. *Id.* BPA intends to offer these rates only to customers that make a purchase commitment to BPA. *Id.*

BPA proposed wide discretion in the structure of the Flexible PF and NR rates. *Id.* Before offering the rates to a customer, however, BPA will ensure that a revenue test has been satisfied. *Id.* at 7-8. The revenue test requires that the revenues for each specific agreement must be the same on a NPV basis that BPA would have received under a strict application of the PF or NR rate schedule. *Id.* at 8. This continues a fundamental principle of the revenue test contained in BPA's current Flexible PF and NR rates. *Id.*

BPA proposed three changes to the Flexible PF and NR rates: (1) eliminating the cash-flow test from the revenue test; (2) prohibiting the use of the Flexible PF and NR rates to flatten out the PF-02 and NR-02 stepped rates; and (3) prohibiting use of the Flexible PF and NR rates for indexed sales. *Id.* The cash-flow test was a requirement that forecasted revenues from all purchasers under the Flexible PF and NR rates would not create an annual cash-flow problem for BPA when compared to forecasted revenues at the charges specified in the PF-96 and NR-96 rate schedules. *Id.* The cash-flow test has been eliminated from the revenue test for a number of reasons. *Id.* First, BPA received very few requests from customers to have lower rates in the beginning of the rate period with higher rates in the later years. *Id.* These are the types of requests that would have affected cash flow in the early years. *Id.* Furthermore, with proposed three- and two-year stepped rates, BPA does not expect to receive many of these requests in the FY 2002-2006 rate period. *Id.* Second, the cash-flow test would create an additional workload for BPA staff. *Id.* If BPA retained the cash-flow test, BPA would have to establish new tracking tools. *Id.* Since BPA expects that it would receive very few of these requests, BPA can reduce workload by not having to create a tracking system. *Id.* Finally, BPA proposed that higher risk sales such as cost-based indexed deals no longer be allowed under this rate. *Id.* at 8-9. For these reasons, the cash-flow test was deemed unnecessary. *Id.* at 9.

Customers cannot use the Flexible PF and NR rates for cost-based indexed purchases. *Id.* Customers can still receive a cost-based index rate, but not through the Flexible PF and NR rates. *Id.* Specific parameters have been established elsewhere for cost-based indexed PF and NR sales. *Id.*; *see* Buskuhl *et al.*, WP-02-E-BPA-21, and ROD section 10.16.1.

The Flexible PF and NR rates cannot be used to change the PF-02 and NR-02 stepped rates to set a rate that is the same for each year of the five-year rate period. Gustafson and Thompson, WP-02-E-BPA-23, at 9. The Flexible PF and NR rates cannot be used to flatten out the stepped rates, because customers can use the five-year posted rate for PF and NR purchases to establish a flat rate for the FY 2002-2006 rate period. *Id.* Customers can, however, use the Flexible PF and NR rates to change the within-year design to obtain a flat rate within the year, or to obtain some other design that better matches their cash-flow needs. *Id.*

Decision

BPA will continue to offer optional flexible demand and energy charges within the PF and NR rate schedules.

10.10.2 Flexible Industrial Firm Power (IP) Rate Option

Issue

Whether BPA should offer optional flexible demand and energy charges within the IP rate schedule.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed to make the Flexible IP rate option available to its DSI customers to better meet customers' needs. Ebberts, WP-02-E-BPA-22, at 11-12.

Evaluation of Positions

BPA proposed to continue the Flexible rate option to its PF and New Resource rate customers, and the same option would also be made available to DSI customers. Ebberts, WP-02-E-BPA-22, at 11-12. While the Flexible rate option ensures that BPA receives the same revenues on a NPV basis that BPA would have received under the posted rates, the Flexible rates allow BPA to structure payments to better meet customers' needs. *Id.* BPA intends to offer this rate option only to DSI customers that make a purchase commitment to BPA under one of the IPTAC rates. *Id.* The Flexible rate option will allow a DSI customer to structure its seasonal and diurnal rates differently than allowed under the posted IPTAC rate schedules. *Id.* Before offering the rates to a customer, however, BPA will ensure that a revenue test has been satisfied. *Id.* The revenue test requires that the revenues for each specific agreement must be the same, on a NPV basis, that BPA would have received under a straight application of the IPTAC rate schedule. *Id.* This continues a fundamental principle of the revenue test contained in previous BPA Flexible rate offers. *Id.* Customers can receive a cost-based indexed rate with the IPTAC, but not through the Flexible rate option. *Id.* Specific parameters have been established elsewhere for the cost-based indexed IP rate. *See* Buskuhl *et al.*, WP-02-E-BPA-21, and ROD section 10.16.2.

Decision

BPA will offer optional flexible demand and energy charges within the IP rate schedule.

10.11 Five-Year Flat-Block Price Forecast

Issue

Whether BPA has properly developed the Five-Year Flat-Block Price Forecast.

Parties' Positions

The DSIs argue that additional resources will be brought online in the western United States over the next three years. DSI Brief, WP-02-B-DS-01, at 32-40. These resource additions will reduce the upward pressure on energy prices, and the escalation in energy prices should begin to revert to the historical negative trend. *Id.* BPA should revise its estimated price for five-year flat-block power to $25.36/MWh. *Id.* The DSIs raised identical arguments in their brief on exceptions. *See* DSI Ex. Brief, WP-02-R-DS-01, at 5. BPA will retain citations to the DSIs' initial brief in the discussion below, but will not add additional citations to their brief on exceptions.

BPA's Position

BPA developed a five-year flat-block price forecast for two purposes. Oliver *et al.*, WP-02-E-BPA-20, at 2. The first purpose is for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id.* The second purpose for this forecast is to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* at 3. BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year block purchases and confirmed this estimate by using a derivation of BPA's Marginal Cost Analysis Study, WP-02-E-BPA-04, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.*

Evaluation of Positions

For the purposes of this rate case, BPA has developed price forecasts to be used in: (1) designing rates; (2) determining surplus revenue; (3) calculating the cash component of the proposed settlement of the REP with regional IOUs; and (4) estimating the cost of augmenting the FBS with five-year flat-block purchases. Oliver *et al.*, WP-02-E-BPA-20, at 2.

For designing rates, BPA relies on the MCA, which uses the AURORA model. *Id.;* Conger *et al.,* WP-02-E-BPA-15. The MCA is described in detail in the testimony of Anderson *et al.,* WP-02-E-BPA-16. The testimony of Keep *et al.,* WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA uses a forecast of prices based on the MCA but with adjustments. Oliver *et al.,* WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger *et al.*, WP-02-E-BPA-15. The five-year flat-block price forecast that BPA has developed for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat-block purchases is discussed below. Oliver *et al.*, WP-02-E-BPA-20, at 2.

BPA has developed a five-year flat-block price forecast for two purposes. *Id.* The first purpose is for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id.* The Power Subscription Strategy, at 8-9, states:

> BPA's strategy is that IOUs may agree to a settlement of the Residential Exchange Program in which they would be able to purchase a specified amount of power under subscription for their residential and small farm consumers at a rate approximately equivalent to the PF Preference rate . . .
>
> In subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of Federal power for the 2002–2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is most cost-effective for BPA.
>
> . . . Any cash payment will reflect the difference between the market price of power forecast in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period . . .

Id. at 2-3. The other forecasts developed for this rate case, as discussed below, are not appropriate for estimating advance purchases of five-year flat-block energy. *Id*. at 3. Therefore, a separate forecast was developed for this purpose. *Id.*

The second purpose for this forecast is to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* BPA's firm obligations and firm resources are described in the Loads and Resources Study, WP-02-E-BPA-01. Some of BPA's firm obligations are met by making purchases during the rate period on an as-needed basis, depending on generation levels, hydro conditions, and weather conditions. Oliver *et al.*, WP-02-E-BPA-20, at 3. In addition, BPA anticipates making substantial purchases prior to the rate period for terms longer than one year to augment the FBS. *Id.* A forecast of the five-year price of the flat-block power acquired in the 1999-2000 market timeframe is a more accurate reflection of the costs and structure of these augmentation purchases than the other price estimates (*e.g.*, AURORA price forecast). *Id.*

BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.*

BPA used real market examples of flat-block forward purchases in its analysis. *Id.* at 4. Prior to the initial proposal, BPA made 250 aMW of block (flat energy) purchases in amounts greater than 25 aMW. *Id.* At the time these purchases were made, 12-month 5-year blocks of energy averaged approximately $26/MWh. *Id.* However, due to the normally expected large surplus from the FCRPS during the spring, BPA chose not to purchase for the months of April, May, and June. *Id.* These purchases were for the nine months (July through March) of each of the five years in the rate period. *Id.* The average price for these purchases was $29.70/MWh. *Id.* BPA expects to supply spring months with BPA's share of secondary energy if it purchases 9-month blocks, or it will purchase the full 12-month block. *Id.* It is BPA's expectation that the purchase of additional forward blocks will place upward pressure on the price of this power. *Id.* BPA expects the price will approach, but not reach, the $32.24/MWh MCA marginal cost. *Id.* Therefore, BPA assumes that as 250 MW increments are purchased, the price will rise from approximately $26/MWh (recent experience) to just over $30/MWh. *Id.* The average price is approximately $28.10/MWh. *Id.* The average price of this range reflects the average purchase price for all purchases. *Id.* At any given time, the prices will be above or below this average, but the average itself stands as a good proxy for the price of the total purchases. *Id.* The higher range of just over $30/MWh represents a high-side estimate for specific new generation based on a compilation of verbal and proprietary commercial information BPA has received on its trading floor from independent power producers, marketers, and other generation developers. *Id.*

BPA used the MCA as a starting point to derive a range of possible five-year flat-block prices. *Id.* The MCA estimates are described in detail in the Marginal Cost Analysis Study, WP-02-E-BPA-04, and the testimony of Anderson *et al.,* WP-02-E-BPA-16. The MCA marginal costs are equal to the hourly variable cost of the marginal resource (the cost associated with the last unit dispatched in least-cost order to meet the next hourly energy demand) for energy available at the Mid-C trading hub. Oliver *et al.*, WP-02-E-BPA-20, at 5. The flat-block price forecast estimated five-year purchases of 2,362 aMW (1,562 aMW of BPA purchases and 800 aMW of IOU purchases). *Id.* Rather than estimating the marginal cost of the last 1 kW, BPA assessed the average price of the last 4,724 aMW of the load associated with the resources on the margin in the WSCC using the AURORA model in the MCA. *Id.* BPA used the MCA price of the last 4,724 aMW because it was twice the level of load BPA is attempting to price. *Id.* Pricing this breadth of marginal resources, rather than the last 1 kW in AURORA, captures a more realistic representation of the prices BPA is likely to encounter when purchasing firm blocks of power for this period. Such a price estimate is more reasonable, because the wholesale market cannot precisely predict a marginal 1 kW price, particularly two years in advance of the sales period. *Id.* The 4,724 aMW of load in the Northwest represents a small fraction of the total energy available, approximately 108,000 aMW from the supply capability in the WSCC, even with the method previously described in this paragraph. BPA acknowledges that sellers of surplus power will attempt to approximate marginal value in the five-year period and sell their highest-cost resources first. *Id.* The conclusion drawn from this analysis is that the prices at which sellers will offer energy supply for five-year flat-block forward purchases will be between the marginal cost price resulting from the decremented load and the marginal cost price that represents the last 1 kW of load. *Id.*

In order to evaluate this broader band marginal analysis, BPA reduced the total load in the Northwest in the MCA by 4,724 aMW, which represents BPA making purchases for load that is being served by new and existing resources. *Id.* The resulting marginal cost price of a 4,724 aMW decrement to load is $23.81/MWh. *Id.* The marginal cost price from the MCA is estimated to be $32.24/MWh for the last kW. *Id.* The average price in this range is $28.03/MWh. *Id.* at 5-6. In summary, using this analytical approach, BPA concluded that parties conducting bilateral negotiations for the FY 2002-2006 period, for quantities of about 2,362 aMW, should expect prices to be between $23.81/MWh and $32.24/MWh with an average of $28.03/MWh. *Id.* at 6.

BPA assessed the future price of power by receiving market quotes from financial institutions for forward transactions in the five-year rate period. *Id.* At the time of the initial proposal, BPA discussed financial swap options with major financial institutions. *Id.* Quotes BPA received were for $28.00/MWh for 250 aMW of flat-block firm energy for the October 1, 2001, through September 30, 2006, period. *Id.*

BPA assessed historical market price escalation and forecast price escalation embodied in the MCA, and then calculated a range of future prices when these escalations are applied to the current market price. *Id.* This technique captures a historical look at market cycles and fundamental market changes inherent in the electricity industry, and a future perspective using the escalation of marginal cost pricing. *Id.* BPA used historical nominal prices for the most likely alternative generation additions from 1980 through 1997. *Id.* The annual escalation of energy prices from these generation sources during this period was minus 2.7 percent, as the marginal resource transitioned from coal generation to natural gas resources. *Id.* In contrast, the more recent market price escalation is reflected in the nominal annual escalation from the MCA for the October 1, 1999, to September 30, 2006, period; that is, 6.2 percent per year. *Id.* Assuming that it is possible for either the historical trend of the 17 years prior to 1997 to occur, or for recent escalation trends to continue over the long run, BPA applied each of these average annual escalation rates to the market price of flat forward blocks sold from October 1999 to September 2000. *Id.* at 6-7. The market price from BPA's trading floor during the initial proposal was approximately $25.50/MWh; applying these growth rates yields an average price range of $22.90/MWh to $32.58/MWh over the October 1, 2001, to September 30, 2006, period. *Id.* at 7. The current market price for the next fiscal year (October 2000 to September 2001) is several dollars higher than the previous year, which illustrates the volatility and upward pressure on the market. Given the wide range of prices possible using historical escalation and forecasted marginal cost escalation, it is reasonable to assert that the price of energy purchases in five-year forward blocks will fall within that range. *Id.*

In summary, based on recent market experience and confirmed by a variety of information using a derivation of the MCA, financial swap quotes, and a reasonable extrapolation of current prices using historical and forecasted assessments of price escalation, BPA has determined that a price of $28.10/MWh reasonably reflects the average long-term purchase price for five-year flat-block energy. *Id.*

The DSIs argue that while BPA staff does not believe that the AURORA marginal cost data is an appropriate direct measure of five-year flat block purchases, BPA staff uses AURORA for its

MCA and to inform the price level at which BPA buys and sells power. DSI Brief, WP-02-B-DS-01, at 33. BPA relies on the MCA, which uses the AURORA model for designing rates. The MCA is described in detail in the testimony of Anderson *et al.*, WP-02-E-BPA-16. The testimony of Keep *et al.*, WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA uses a forecast of prices based on the MCA but with adjustments. Oliver *et al.*, WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger *et al.*, WP-02-E-BPA-15. The five-year flat-block price forecast that BPA has developed for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat-block purchases is discussed below. Oliver *et al.*, WP-02-E-BPA-20, at 2.

BPA relies on the MCA for designing rates, and BPA uses an adjusted price forecast based on the MCA for determining surplus revenues. Oliver *et al.*, WP-02-E-BPA-20, at 2. However, these forecasts are not appropriate for determining the price of five-year block purchases. *Id.* The MCA estimates are described in detail in the Marginal Cost Analysis Study, WP-02-E-BPA-04, and Anderson *et al.*, WP-02-E-BPA-16. *Id.* The MCA marginal costs are equal to the hourly variable cost of the marginal resource (the cost associated with the last unit dispatched in least-cost order to meet the next hourly energy demand) for energy available at the Mid-C trading hub. *Id.* There are several reasons why a forecast of the hourly marginal cost and a forecast of prices from a combination of daily, within-month, monthly, and annual products are not appropriate measures of five-year flat-block purchases. *Id.*

The structure of a five-year forward block purchase is not similar to an hourly product that is subject to real-time pricing based on the last 1 kW of demand. *Id.* at 8. As previously described, the MCA marginal costs are equal to the hourly variable cost of the marginal resource for energy available at the Mid-C trading hub, essentially the variable cost of the last 1 kW generated. *Id.* Five-year forward block purchases do not reflect the last 1 kW generated. *Id.* Rather, they reflect market participants' willingness to sell generation above their variable cost. *Id.* The MCA marginal cost estimates are used as an indication of what BPA expects to actually experience in the real-time market-clearing price for hourly bulk energy transactions during the rate period. *Id.* In contrast, these five-year blocks will be acquired in advance of the five-year period through bilateral agreements. *Id.* Further, the product that BPA is expecting to acquire is five-year, flat annual energy blocks over all hours of the year irrespective of overall demand levels and in amounts greater than one kW. *Id.* Therefore, using the MCA marginal cost estimates as a forecast for five-year block purchases is not appropriate. *Id.*

In addition, market participants do not have uniform or perfect information with respect to future supply and demand levels or market and economic conditions, particularly for periods starting 24 to 60 months in the future. *Id.* AURORA models the functioning of a competitive economic market system that has a theoretical solution of information and timing. *Id.* The market can generate solutions different from a theoretical model, because market participants are individually making decisions to build generating resources in the Northwest to meet perceived demand. *Id.* Market participants may be willing to sell below the expected marginal cost and above their variable cost for many reasons, including: to ensure cost recovery of a capital investment, to hedge against a high future risk exposure, and simply because they have a different view of the future market. *Id.* at 8-9. Market participants use bilateral transactions to diversify their portfolio of sales and cover purchases made to lock in an acceptable margin. *Id.* at 9.

Another reason why these forecasts are not appropriate measures of five-year flat-block purchases is that the risk profiles of buyers and sellers fundamentally diverge. *Id.* Sellers of assets are more likely to lock in prices above their variable costs to protect from the risk of a low market than to wait for potential high markets. *Id.* On the other hand, because buyers generally have a higher risk profile, they can either purchase when prices are perceived to be "reasonable" or wait to buy. Potential high markets for buyers pose less risk, because buyers have more substitution options than sellers. *Id.* Buyers can substitute electricity with gas and, of course, buyers can readily go out of business. *Id.* The result of the divergence of risk profiles enables transactions to occur at less than the expected hourly market clearing price. *Id.* Some market participants are likely to sell forward to hedge the risk of a lower market. *Id.* This market speculation contributes to energy available at a range of prices. *Id.*

BPA used AURORA and the resulting MCA price estimates to derive *a* range of possible five-year flat-block prices. Oliver *et al*., WP-02-E-BPA-20, at 4. BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. *Id.* BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year flat-block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year flat-block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.* at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation, which provides strong support for the price forecast of $28.10. Oliver *et al*., WP-02-E-BPA-45, at 2.

The DSIs note that they reviewed and proposed changes to the inputs to the AURORA model. DSI Brief, WP-02-B-DS-01, at 33. The DSIs concluded that AURORA results were fairly sensitive to the absolute amount and type of generation specified in the inputs. *Id.* The AURORA model has iterative logic that assumes new generation will be built exactly when market prices will pay for the generation. *Id.* The DSIs argue that while they agree with the theoretical soundness of AURORA logic, the actual markets can be volatile and do not respond exactly according to theory. *Id.* The DSIs argue that the supply/demand balance is a significant factor for price, and that if demand approaches the limits of physical supply, generation with higher variable costs is brought into operation, and the higher prices encourage developers to install new generation with prices eventually moderating to the full cost of new resources. *Id.* at 34. The DSIs argue that the opposite is also true, as demonstrated by BPA's AURORA test to confirm its estimate of the cost of five-year flat-block power. *Id.* When BPA reduced total load in the Northwest by 4,724 aMW, the resulting marginal cost of the decremented load was $23.81/MWh, significantly lower than BPA's $32.24/MWh average annual marginal cost of undecremented load. *Id.* First, it should be noted that issues regarding the AURORA model are addressed in detail in ROD chapter 4, Marginal Cost Analysis. However, in response to the DSIs' arguments on the five-year flat-block forecast, as previously noted, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Abundance of supply and constraints on supply are addressed in the combination of the four methods, which accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2.

First, using actual market experience contemplates pricing cycles and uncertainty, in that sellers today will sell based on their evaluation of generating resources coming online and the possible resulting decline in market prices. *Id.* Otherwise, all sellers would simply hold their supply until a future date to sell at a higher price. *Id.*; Oliver *et al.*, WP-02-E-BPA-20, at 8.

Second, by using a derivation of the MCA and the AURORA model, BPA has implicitly evaluated the five-year flat-block price forecast in the context of market cycles. Oliver *et al.*, WP-02-E-BPA-45, at 2. The MCA assumes generation coming online and being retired, which could contribute to a pricing cycle(s). *Id.* BPA has acknowledged that sellers today will price blocks of power for less than the last 1 kW of load, or the marginal cost of new generation. *Id.* at 2-3; Oliver *et al.*, WP-02-E-BPA-20, at 5, 8-9. BPA analyzed this situation by decrementing the load forecast in the MCA with twice the level of BPA's expected purchases. Oliver *et al.*, WP-02-E-BPA-45, at 3. This analysis results in a price of $23.81/MWh compared to a price of $32.24/MWh in the MCA. *Id.* Comparing this with BPA's estimated price of $28.10/MWh, BPA concludes that it is reasonable that the average price of BPA's potential purchases will be between the price resulting from decrementing load in the WSCC and the last 1 kW. *Id.*

Third, the very pricing mechanism used by financial institutions to develop market quotes hinges on market volatility, which contemplates market cycles. *Id.*

Fourth, BPA directly acknowledges market cycles by extrapolating market prices (current during the initial proposal) using the historical market price escalation and the forecast price escalation in the MCA. *Id.* This technique captures a historical look at market cycles and fundamental market changes inherent in the electricity industry, and a future perspective using the escalation of marginal cost pricing. *Id.*; Oliver *et al.*, WP-02-E-BPA-20, at 6. The result of this analytical technique is a range of prices from $22.90/MWh to $32.58/MWh. *Id.* BPA's estimated price of $28.10/MWh falls well within this range, the range within which market cycles are likely to occur. Oliver *et al.*, WP-02-E-BPA-45, at 3.

In summary, by using four approaches to derive and confirm BPA's five-year flat-block market price forecast, BPA demonstrated that it not only contemplated market cycles and variations resulting from changes in generation but also factored them into BPA's evaluation. *Id.* Nonetheless, it is BPA's experience that market price changes occur due to a variety of factors besides generation plant additions, such as economic conditions, hydrologic conditions, fuel prices, regulatory/legislative decisions, and generation plant retirements. Oliver *et al.*, WP-02-E-BPA-45, at 5.

The DSIs argue that decrementing load will tend to affect marginal costs in a manner similar to adding an equivalent amount of new generating capability. DSI Brief, WP-02-B-DS-01, at 34. For valid AURORA results, the DSIs claim it is therefore necessary to take into account any generation not included in the initial AURORA inputs but that could conservatively be expected to be online during the 2002-2006 rate period. *Id.* The DSIs argue that almost 17,000 MW of new generation has been proposed for construction in California, over 5,000 MW in the PNW, almost 2,000 MW in Canada, and almost 1,000 MW in the remainder of the WSCC region. *Id.* at 34-35. The DSIs argue that the level of proposed generation suggests that an increase in the price of power over the last three years is leading to an increase in planned generation. Thus, it was necessary to include in AURORA inputs for that portion of the proposed generation that had a high likelihood of actually being constructed before or during the rate period. *Id.* at 35. As noted previously, issues regarding the AURORA model are addressed in detail in ROD chapter 4, Marginal Cost Analysis. In response to these arguments, however, as previously noted, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

Both BPA's initial proposal and the DSIs' proposal consider adding new generation. The Joint DSIs' approach directly inputs (hardwires) an exogenous forecast of new generation. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. The BPA approach adds new resources based on standard economic logic. Anderson *et al.*, WP-02-E-BPA-42, at 7. The BPA approach will add new generation when a resource's revenues exceed its costs. *Id.*

The new generation forecast proposed by the DSIs lacked background substantiation. *Id.* at 8. This approach did not address the detailed specifics of forecasting cyclical prices. *Id*. at 7-8. The DSIs also did not describe how historical cycles are appropriate, or may adapt, to a changed electric market-driven by independent power producers and smaller scale generation. *Id.* at 8. The data provided by the DSIs produced results in conflict with the DSIs' testimony. *Id.* at 3. BPA could not adopt data that was inconsistent with the supporting testimony. BPA added new generation based on the economic logic in AURORA. *Id.* at 7. This method is based on economic logic rather that an exogenous forecast prepared by the DSIs. *Id.* at 7. The method used by BPA to forecast new generation is reasonable.

The DSIs argue that the AURORA logic adds generic resources at generic costs when economical and that AURORA is, in effect, a combined forecast. DSI Brief, WP-02-B-DS-01, at 35. While the DSIs do not take issue with the appropriateness of such a forecast, they argue that AURORA must be supplied accurate inputs, including generation sufficiently along in the planning and construction process to make it likely to be brought online. *Id.* The DSIs argue that the amount of generation in question is not a forced overbuild scenario, but simply moderates the rise in prices that would otherwise occur as the AURORA results converge toward the long-term incremental cost of generation. *Id.* As previously noted, however, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

BPA agrees that reasonable data should be supplied to derive a reasonable forecast. The basic inputs driving BPA's forecast of new generation are the annual load forecast and the cost of new resources. *See* ROD chapter 4. No party raised any issue with respect to these variables. The methodology which uses these data to derive a new generation forecast is based on standard economic logic and was supported by WPAG. Cross *et al.*, WP-02-E-WA-02, at 35-37.

The new generation forecast proposed by the DSIs lacked background substantiation. Anderson *et al.*, WP-02-E-BPA-42, at 7-8. This approach did not address the detailed specifics of forecasting cyclical prices. *Id.* at 7-8. The DSIs also did not describe how historical cycles are appropriate, or may adapt, to a changed electric market-driven by independent power producers and smaller scale generation. *See* ROD chapter 4. The data provided by the DSIs produced results in conflict with the DSIs' testimony. *Id*. at 3. BPA could not adopt data that were inconsistent with the supporting testimony.

The DSIs argue that in addition to the existing resources available to AURORA, the DSIs included 4,823 MW of planned new generation with completion dates through 2002. DSI Brief, WP-02-B-DS-01, at 36. The DSIs included about 147 MW of renewable generation funded from California public purpose fees and about 3,000 MW of new merchant generation as a conservative estimate of new generation that would come online in California in the near term. *Id.* The DSIs argue that the generation they have noted is expected to come online earlier than the generic generation that AURORA would construct, but the total amount (4,823 MW) is less than AURORA would build (8,000 MW). *Id.* As noted previously, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2. Further, it is BPA's experience that market price changes occur due to a variety of factors besides generation plant additions, such as economic conditions, hydrologic conditions, fuel prices, regulatory/legislative decisions, and generation plant retirements. *Id*. at 5. BPA acknowledges that the DSIs have a different forecast of new generation than BPA. BPA's forecast of new generation is reasonable. *See* ROD chapter 4, which fully describes BPA's criteria for its decision on the DSIs' proposal for their exogenous forecast of new generation.

The DSIs argue that as the new generation completed before the end of 2002 comes online: (1) the hourly marginal costs generated by AURORA will be lower by roughly the same amount as the hourly marginal costs decreased when BPA removed 4,724 aMW of load from the AURORA inputs; and (2) the cost of augmenting BPA's system with flat-block power will be less. DSI Brief, WP-02-B-DS-01, at 36. It is important for BPA to evaluate the amount of generation likely to come online over the next three years and to take into account the effect of this generation on the cost of augmentation. *Id.* Further, the DSIs argue that the resources they forecast will be installed in the WSCC are based on the DSIs' detailed analysis of real world construction plans described in their testimony. DSI Brief, WP-02-B-DS-01, at 37. The DSIs argue that BPA should take account of these real world plans in its own forecast of the market price of block purchases. *Id.* at 37-38. Again, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2. *See also* *Id*. at 5. BPA has reviewed and commented on the data proposed by the DSIs for new construction. This analysis is included in ROD chapter 4. BPA's data and method for forecasting new generation are reasonable. This analysis is also included in Chapter 4.

The Joint DSIs' forecast of new generation is based, in part, on an analysis of historical cyclical factors. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. The DSIs have not provided a complete analysis of this cyclical pattern. Anderson *et al.*, WP-02-E-BPA-42, at 7-8. The DSIs have not noted how a historical cyclical pattern may change in an evolving electric power market. *Id.* at 7-8. The DSIs' data produce results that are inconsistent with the results of their testimony. *Id.* at 3. BPA could not use DSI data that BPA could verify was inconsistent with the DSIs' testimony.

The DSIs argue that BPA's marginal cost panel acknowledged that there are resources under construction in the geographic area modeled by AURORA. DSI Brief, WP-02-B-DS-01, at 36-37. The panel also acknowledged that the inputs it used in AURORA to develop market prices did not reflect any such resources. *Id.* at 37. The panel agreed that the costs of completing and then operating a previously partially complete resource were less than building and operating a resource from scratch. *Id.* The BPA panel also acknowledged that if one were to include partially completed resources, then such resources would be selected by AURORA prior to generic greenfield resources and may be placed in operation at an earlier time than a greenfield resource. *Id.* BPA did not make any independent judgment of whether the new resources that the DSIs believed were sufficiently far along in the planning and construction process to be reasonably certain of being completed and brought online would in fact be constructed. *Id.* In response to these arguments, as noted above, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

The effects of new generation on marginal costs are fully accounted for in BPA's MCA. Anderson *et al.*, WP-02-E-BPA-42, at 7. BPA reviewed and commented on the approach and data proposed by the DSIs for forecasting new generation. *Id.* at 6-8. BPA's approach relies on standard economic logic to forecast new generation. Anderson *et al.*, WP-02-E-BPA-16, at 3-4. The Joint DSIs' approach relies on an exogenous forecast. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. BPA's input data to the forecast of new generation were fully documented. Marginal Cost Analysis Study Documentation, WP-02-E-BPA-04A, at 3-10. No party critiqued the basic input data driving BPA's forecast of new generation. BPA commented on the applicability of the DSIs' data to forecasting new generation. Anderson *et al.*, WP-02-E-BPA-42, at 6-8. The DSIs' data were not consistent with the results of the DSIs' testimony. *Id.* at 3.

The DSIs argue that five-year flat blocks of power for the rate period will cost about $25/MWh. DSI Brief, WP-02-B-DS-01, at 38. The DSIs recommend that BPA use a price of $25.36/MWh in its rate case calculations, which is the average of two marginal costs developed by AURORA with the changes proposed by the DSIs. *Id.* The DSIs ignore that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

BPA could not verify the DSIs' MCA forecast and thus the $25.36/MWh price. Anderson *et al.*, WP-02-E-BPA-42, at 3. BPA requested the DSIs' MCA AURORA output data base by means of a data request, but the DSIs did not supply BPA the results. *Id.* at Attachment 4. In data response BPA-DS/AL/VN:039, the Joint DSIs state "The requested output file is not available …. If we are able to reconstruct an output file that reflects our AURORA results, it will be provided to you." *Id.* at Attachment 4. BPA did not receive the output file. *Id.* at 4. BPA continues to rely on the four methods used to derive the $28.10/MWh, and BPA's reliable and verifiable results from AURORA.

The DSIs argue that BPA claimed that the added generation is not enough to significantly affect the AURORA price forecast, in that the resource addition changes the marginal cost from 32 mills/kWh to 29.6 mills/kWh. DSI Brief, WP-02-B-DS-01, at 38, citing Oliver *et al.*, WP-02-E-BPA-45, at 4. The DSIs argue that the marginal cost from BPA's MCA run is $32.24/MWh. *Id.*, citing Oliver *et al.*, WP-02-E-BPA-20, at 5. The DSIs argue that the difference between the MCA results with and without the resource addition is $2.64/MWh, almost identical to the difference between BPA's estimated flat-block price of $28.10/MWh and the $25.36/MWh the DSIs developed recognizing that some resource additions in the western United States are almost certain to be online before 2002. *Id.* The DSIs fail to note that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Using the four approaches to derive and confirm its five-year block price forecast, BPA has captured the range around price uncertainty due to possible market variations (price and market cycles) and, therefore, $28.10 is a reasonable estimate. Oliver *et al.*, WP-02-E-BPA-45, at 8. Furthermore, BPA's five-year flat-block price forecast for a block purchase reflects a mid-range price between historical and forecast escalation rates, which accounts for the possibility of price volatility due to new generation development. *Id*. at 5.

The DSIs argue that the $25.36/MWh estimate is consistent with the data BPA staff reviewed. DSI Brief, WP-02-B-DS-01, at 38. The current market price (at the time of the initial proposal) from BPA's trading floor is approximately $25.50/MWh, citing WP-02-E-BPA-20, at 7. The historical price escalation for energy from generation sources from 1980 through 1997 is minus 2.7 percent per year, although recent escalation has been 6.2 percent per year. *Id.* at 38-39. The DSIs claim that the long-term price trend for energy is downward, and the increasingly competitive market for electricity makes it likely that the trend will continue for the time being. *Id.* They further argue that giving equal weight to the long-term trend in escalation and the very recent energy price runups produces an average market cost of $27.74/MWh. *Id.* at 39. The DSIs assert that if energy prices revert to the long-term trend, as they say is typical following a runup in prices, the expected value in the 2002-2006 period is much more likely to be in the range of $25/MWh or less. *Id.* It is important to note that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using the historical and estimated future escalation was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Using the four approaches to derive and confirm its five-year block price forecast, BPA has captured the range around price uncertainty due to possible market variations (price and market cycles) and, therefore, $28.10 is a reasonable estimate. *Id*. Furthermore, BPA's five-year flat-block price forecast for a block purchase reflects a mid-range price between historical and forecast escalation rates, which accounts for the possibility of price volatility due to new generation development. Oliver *et al.*, WP-02-E-BPA-45, at 5. Further, BPA believes that price escalation will likely be more toward the center of the range of the escalation in the MCA price forecast and escalation of historical prices. *Id*. at 7. BPA believes this based on the results of the three other techniques BPA used to examine its price estimate: actual market experience, a derivation of the MCA and the AURORA model, and market quotes for forward transactions. *Id.*

The DSIs argue that BPA has been making flat nine-month purchases for prices that average $29.70/MWh. DSI Brief, WP-02-B-DS-01, at 39. The DSIs state that BPA assumes it can purchase or sell flat spring energy for $16.12/MWh. *Id.* The annual average of these prices is $26.30/MWh. *Id.* BPA has assumed that as it purchases additional forward blocks, there will be upward pressure on the block price. *Id.* The DSIs argue that BPA's block purchases do not represent incremental load to the market. *Id.* The DSIs argue that to the extent BPA purchases power to serve new loads on BPA, represented by a return of public agency load diversified during 1996-2001 and 1,000 aMW of sales to the IOUs, the power currently serving these same loads will be released to the market. *Id.* Therefore, the DSIs assert that BPA's purchases do not represent an increase in demand and will not put pressure on the market price. *Id.* The DSIs claim that the downward price pressure created by planned new generation will result in reductions, not increases, in market prices. *Id.* BPA agrees with the concept that the augmentation load is not new load but returning load. These points are described in Oliver *et al.,* WP-02-E-BPA-20, at 5-6. However, BPA does not agree with the methodology of resource additions proposed by the DSIs. These points are addressed in ROD chapter 4. Furthermore, BPA does not agree that "planned generation" will result in downward pressure on prices. BPA recognizes that there is uncertainty in future market prices and that there will be a range of opinions as to whether the future price of power may be higher, lower, or relatively the same compared to current prices. Oliver *et al.*, WP-02-E-BPA-20, at 4. Applying the historical market price escalation rate and the marginal cost price forecast escalation rate in the MCA demonstrates this wide range of possibilities. *Id.;* Oliver *et al.,* WP-02-E-BPA-20, at 6-7. BPA believes that the market will likely assess the prices for five-year flat-block purchases within the aforementioned range, and that $28.10/MWh is a reasonable assessment of a price point. Oliver *et al.*, WP-02-E-BPA-45, at 4.

BPA has reviewed its testimony and has confirmed that by using four approaches to derive and confirm its five-year flat-block price forecast, BPA has captured the range around price uncertainty due to possible price and market cycles. Oliver *et al.*, WP-02-E-BPA-45, at 8.

<u>Decision</u>

BPA has properly established the Five-Year Flat-Block Market Forecast.

10.12 Low Density Discount (LDD)

In order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA applies a discount, to the extent appropriate, to BPA's rates for such purchasers. Gustafson and Thompson, WP-02-E-BPA-23, at 2. In BPA's initial proposal, these rates included the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the Residential Load (RL-02) rate, and the New Resources (NR-02) rate. *Id.* In BPA's initial proposal, the LDD applied to the following components of the foregoing rate schedules: (1) Demand; (2) HLH energy purchases; (3) LLH energy purchases; and (4) Load Variance. *Id.*

The methodology for calculating the LDD is explained in detail in BPA's Wholesale Power Rate Schedules, WP-02-E-BPA-07. In summary, a purchaser must satisfy five eligibility criteria. *Id.* Two of these criteria regard having a K/I (sales to investment) ratio less than 100 and a C/M (consumers per mile) ratio less than 12. *Id.* If a purchaser does not meet the five eligibility requirements, its LDD is zero. *Id.* If the purchaser satisfies the five requirements, the purchaser is eligible for the LDD. *Id.* Under the proposed methodology, BPA established a list of discounts that apply to the numerical results of the calculation of the two respective ratios. *Id.* The purchaser will receive the sum of the two potential discounts, but not in excess of 7 percent. *Id.* If the purchaser's revised discount varies from its current discount by more than one-half of 1 percent, BPA would progressively phase in the revised discount in annual increments of one-half of 1 percent until the purchaser receives its then-final revised discount. *Id.* Once the percentage discount is determined, the discount would be applied each month to the charges (excluding UAI Charges, Excess Factoring Charges, and charges for transmission services) for all power purchased from BPA under the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. *Id.* at 2-3. The LDD reduces the recipient's monthly power bill by the applicable discount. *Id.* at 3.

Issue 1

Whether BPA should eliminate the Additional Adjustment for Very Low Densities.

Parties' Positions

Numerous parties advocate the retention of the Additional Adjustment for Very Low Densities. NRU Brief, WP-02-B-NI-02, at 19-20; PNGC Brief, WP-02-B-PN-01, at 22; PPC Brief, WP-02-B-PP-01, at 43.

BPA's Position

In BPA's direct testimony, BPA proposed to eliminate the Additional Adjustment for Very Low Densities. Gustafson and Thompson, WP-02-E-BPA-23, at 3. In BPA's rebuttal testimony, BPA advocated continuing the adjustment. Gustafson *et al.*, WP-02-E-BPA-48, at 2.

Evaluation of Positions

The Additional Adjustment for Very Low Densities was a feature of BPA's 1996 LDD that provided an additional discount of one-half percent to purchasers with a C/M ratio of 3 or less and a K/I ratio of 26 or less. Gustafson and Thompson, WP-02-E-BPA-23, at 3. In its initial proposal, BPA proposed to eliminate this adjustment because, of over 55 purchasers that receive the LDD, only one purchaser currently qualifies for this provision. *Id.* In BPA's rebuttal testimony, BPA noted that a number of parties argued that BPA should retain the Additional Adjustment for Very Low Densities. Gustafson *et al.*, WP-02-E-BPA-48, at 2. *See* Saven *et al.*, WP-02-E-NI-02, at 3-6; Thayer *et al.*, WP-02-E-PN-03, at 2-5; Hansen and O'Meara, WP-02-E-PP-08, at 2-3. In support of this position, the parties argued that: (1) even if only one utility is currently receiving the Additional Adjustment for Very Low Densities, it is still a valid provision; (2) there may be more than one utility eligible for the Additional Adjustment for Very Low Densities during the rate period; and (3) the time and expense to implement the Additional Adjustment for Very Low Densities is greatly exceeded by the benefits provided to purchasers. Gustafson *et al.*, WP-02-E-BPA-48, at 2. BPA concluded that the parties' arguments were well reasoned. *Id.* Based on those arguments, BPA proposed to continue the Additional Adjustment for Very Low Densities for the next rate period. *Id.* BPA will continue to monitor the Additional Adjustment for Very Low Densities, however, to ensure that there are still utilities eligible to receive the Additional Adjustment for Very Low Densities and that it continues to serve a valuable purpose. *Id.*

Decision

BPA will continue the Additional Adjustment for Very Low Densities.

Issue 2

Whether BPA should use TRL to define the power sales used in calculating "K" in the K/I ratio.

Parties' Positions

The parties did not generally oppose BPA's proposed change in calculating K. PNGC requests that BPA make clear that load that is supplied by a utility to a retail customer that is not on the utility's distribution system does not count toward TRL. PNGC Brief, WP-02-B-PN-01, at 23-24.

BPA's Position

In a retail access situation, the purchaser receiving an LDD may not be providing all of the power, or kWh, to the end-use consumer. Gustafson and Thompson, WP-02-E-BPA-23, at 3-4. The definition of K therefore, must be changed to reflect the possible development of retail access. *Id.* The proposed definition identifies the purchaser's "TRL" as the proper basis to calculate K. *Id.*

Evaluation of Positions

BPA's 1996 Wholesale Power and Transmission Rate Schedules, in the section governing the calculation of K for the K/I ratio, state that "[t]he Purchaser's total electric energy requirements include firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses." Gustafson and Thompson, WP-02-E-BPA-23, at 3. In a retail access situation, however, the purchaser may not be providing all of the power, or kWh, to the end-use consumer. *Id.* The definition of K therefore, must be changed to reflect the possible development of retail access. *Id.* at 3-4. The new definition identifies the purchaser's "TRL" as the proper basis to calculate K. TRL is defined, in pertinent part, as ". . . all electric power consumption within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources." *Id.* at 4. This change is appropriate for two reasons. *Id.* First, this would avoid LDD costs increasing as a result of a purchaser losing load, or kWh, to another supplier and having the purchaser's K decrease. *Id.* The purchaser would still be able to recover investment in their system through a distribution charge that most likely would not be tied to kWh sales. *Id.* Second, TRL is defined and used for several purposes in BPA's rate schedules. Using the term in the LDD keeps consistency throughout the rate schedules. *Id.*

PNGC notes that BPA did not want "K" to decrease to reflect a loss of power sales due to load being served by another power supplier. PNGC Brief, WP-02-B-PN-01, at 23. PNGC argues that this addresses only half of the problem. *Id.* A similar but opposite issue exists when load is gained through retail access. *Id.* PNGC argues that it is important to ensure that the current definition of TRL holds the LDD constant for either loss or gain due to retail access. *Id.* at 23-24. Therefore, if an LDD utility became the supplier for load that was not on its distribution system under some sort of retail access scenario, that off-system load should not be counted in the utility's TRL. *Id.* at 24. This solution would prevent an unfair increase in the "K" value that would result in a lower LDD value. *Id.* PNGC requests that BPA make clear that load that is supplied by a utility to a retail customer that is not on the utility's distribution system does not count toward TRL. *Id.* BPA agrees with PNGC's position. If an LDD utility becomes the supplier for load that is not on its distribution system under some sort of retail access scenario, that off-system load will not be counted in the utility's TRL. This interpretation is consistent with the definition of TRL in BPA's initial proposal. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 125.

Decision

BPA will use the purchaser's TRL as the proper basis to calculate K. Under some sort of retail access scenario, if an LDD utility becomes the supplier for load that is not on its distribution system, that off-system load will not be counted in the utility's TRL.

Issue 3

Whether BPA should revise the definition of consumers for the C/M ratio.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed that "[t]he C/M is calculated by dividing the maximum number of consumers on the distribution system, in any one month during the Calendar Year (CY), by the end of CY number of pole miles of distribution." Gustafson and Thompson, WP-02-E-BPA-23, at 4. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99.

Evaluation of Positions

BPA proposed that "[t]he C/M is calculated by dividing the maximum number of consumers on the distribution system, in any one month during the Calendar Year (CY), by the end of CY number of pole miles of distribution." Gustafson and Thompson, WP-02-E-BPA-23, at 4. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99. This clarification of consumers is necessary for two reasons. Gustafson and Thompson, WP-02-E-BPA-23, at 4. The first reason is to eliminate confusion regarding service to irrigation and seasonal consumers. *Id.* Some purchasers have previously averaged the months of service to irrigation and seasonal accounts and not counted them as 12-month consumers. *Id.* This is incorrect and affords the purchaser a higher LDD than is intended. *Id.* The second reason for this revision is to define which consumers to count in a retail access environment; that is, whether one counts the consumers to whom the purchaser sells power, or the consumers on the purchaser's distribution system. *Id.* BPA proposed that purchasers use the number of consumers on their distribution system. *Id.* The LDD was developed to offer benefits for purchasers with low-density systems to help offset the higher than usual distribution costs. *Id.* at 4-5. By counting the consumers on the distribution system, and not all consumers purchasing power from the purchaser, the LDD benefits stay with the distribution consumers. *Id.* at 5.

Decision

BPA will calculate the C/M ratio by dividing the maximum number of consumers on the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Issue 4

Whether BPA should base the calculation of pole miles on the end of CY number of pole miles of distribution.

Parties' Positions

NRU argued that BPA should clarify the collection of data concerning the number of miles of distribution line for purposes of calculating the C/M ratio to provide that it does not exclude underground distribution lines from the calculation. Saven *et al.*, WP-02-E-NI-02, at 10.

BPA's Position

BPA proposed that the determination of pole miles should be based on the end of CY number of pole miles of distribution. Gustafson and Thompson, WP-02-E-BPA-23, at 5.

Evaluation of Positions

BPA's 1996 LDD requires purchasers to submit an average of two years of data on pole miles. Gustafson and Thompson, WP-02-E-BPA-23, at 5. BPA proposed that the determination of pole miles should be based on the end of CY number of pole miles of distribution. *Id.* This would simplify reporting requirements, thereby reducing the time it takes for purchasers to report to BPA and for BPA to implement the LDD. *Id.*

NRU argued that BPA should clarify the collection of data concerning the number of miles of distribution line for purposes of calculating the C/M ratio to provide that it does not exclude underground distribution lines from the calculation. Saven *et al.*, WP-02-E-NI-02, at 10. In rebuttal testimony, BPA noted that the reference to pole miles and the definition of pole miles in the 2002 initial proposal Wholesale Power Rate Schedules, WP-02-E-BPA-07, includes underground distribution lines. Gustafson *et al.*, WP-02-E-BPA-48, at 3.

Decision

The determination of pole miles will be based on the end of CY number of pole miles of distribution. The reference to pole miles and the definition of pole miles in BPA's 2002 Wholesale Power Rate Schedules includes underground distribution lines.

Issue 5

Whether BPA has proposed an appropriate effective date for LDD changes.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed that any changes to a purchaser's LDD amount should start on October 1 of each year. Gustafson and Thompson, WP-02-E-BPA-23, at 5.

Evaluation of Positions

BPA proposed that any change in a purchaser's LDD will be determined by application of the criteria described above to the data submitted by a purchaser by June 30 of each year. Gustafson and Thompson, WP-02-E-BPA-23, at 5. This will eliminate confusion over when a change to a purchaser's LDD is to take place. *Id.* There will be no retroactive changes. *Id.* All changes that are determined by data submitted by June 30 will occur on the upcoming October 1. *Id.*

Decision

All LDD changes that are determined by data submitted by June 30 will occur on the upcoming October 1.

Issue 6

Whether BPA should adopt a Benefits Legislation Exclusion.

Parties' Positions

Numerous parties opposed the adoption of a Benefits Legislation Exclusion. PNGC Brief, WP-02-B-PN-01, at 22; NRU Brief, WP-02-B-NI-02, at 19-20; PPC Brief, WP-02-B-PP-01, at 43-44.

BPA's Position

In BPA's initial proposal, BPA advocated a Benefits Legislation Exclusion and included it as part of the definition of the LDD in the GRSPs. Gustafson and Thompson, WP-02-E-BPA-23, at 5; Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 101-02. In its rebuttal testimony, BPA proposed that it is unnecessary at this time to include a Benefits Legislation Exclusion in the definition of the LDD. Gustafson *et al.*, WP-02-E-BPA-48, at 2-3.

Evaluation of Positions

The initially proposed Benefits Legislation Exclusion provided that if the Federal government or a state or local government adopted a law, regulation, or other provision that provides benefits similar to the LDD, then the purchaser's service territory within the jurisdiction of that provision would no longer be eligible to receive the LDD. Gustafson and Thompson, WP-02-E-BPA-23, at 6. The exclusion was intended to preclude the possibility of a utility benefiting from the LDD when the utility is able to benefit from a separate program for a similar purpose. *Id.* A number of parties opposed the Benefits Legislation Exclusion, citing numerous concerns. *See* Saven *et al.*, WP-02-E-NI-02, at 6-8; Thayer *et al.*, WP-02-E-PN-03, at 6-8; and Hansen and O'Meara, WP-02-E-PP-08, at 3-4. While BPA disagreed with virtually every argument raised by the parties in opposition to the Benefits Legislation Exclusion, BPA reconsidered its proposal to adopt the exclusion. Gustafson *et al.*, WP-02-E-BPA-48, at 2-3. BPA believes that the policy underlying the Benefits Legislation Exclusion is sound. *Id.* The Benefits Legislation Exclusion was created by BPA in response to legislative efforts to establish benefit programs similar to the LDD. *Id.* It is reasonable to consider whether BPA should offer an LDD when similar benefits are provided by other governmental entities. *Id.* Since the conception of the Benefits Legislation Exclusion, however, BPA has not witnessed the adoption of such provisions by state or local governments. *Id.* While BPA believes that it may be inappropriate for utilities to receive the LDD at the same time that such utilities benefit from similar programs provided elsewhere, BPA does not believe it is necessary to establish the Benefits Legislation Exclusion at this time. *Id.* BPA will continue to monitor retail access legislation on the Federal, state, and local government level to determine whether LDD benefits are being duplicated by another government's actions. *Id.* The provision of benefits similar to the LDD by other governmental entities during the rate period may require BPA to revisit this issue in its next rate proceeding. *Id.*

Decision

BPA does not include a Benefits Legislation Exclusion in the LDD.

Issue 7

Whether BPA should include a Retail Access Exclusion in the LDD.

Parties' Positions

NRU argues that BPA should clarify that the Retail Access Exclusion does not apply to new service resulting from bypass, utility mergers, the annexation of territory, or the acquisition of territory by voluntary purchase agreement. NRU Brief, WP-02-B-NI-02, at 20. PacifiCorp objects to BPA's proposal to extend eligibility to load gained through bypass or annexation of territory, so long as PacifiCorp's residential customers in southern Idaho are denied the benefits. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5.

BPA's Position

BPA proposed the adoption of a Retail Access Exclusion, which precludes LDD benefits for purchasers' new loads where the acquisition of the new load occurs as a result of retail access legislation by the Federal Government or a state or local government. Gustafson and Thompson, WP-02-E-BPA-23, at 6-7. BPA does not intend to have the Retail Access Exclusion prohibit the application of the LDD under circumstances that have been allowed prior to voluntary or mandatory retail access.

Evaluation of Positions

The Retail Access Exclusion precludes LDD benefits for purchasers' new loads where the acquisition of the new load occurs as a result of retail access legislation by the Federal Government or a state or local government. Gustafson and Thompson, WP-02-E-BPA-23, at 6-7. The gaining purchaser cannot provide the benefits of the LDD to the gained load. *Id.* If the acquisition would have been allowed prior to Retail Access Legislation, then the gained load is still eligible for LDD benefits. *Id.* The calculations for determining the LDD discount percentage are derived from consumers, costs, and sales associated with the purchaser's distribution system. *Id.* Therefore, the benefits of the LDD should stay with the consumers on the purchaser's distribution system. *Id.* This exclusion was proposed because some of BPA's customers that are not eligible to receive the LDD were concerned that, with the advent of retail access, customers receiving the discount would use LDD benefits as a means of acquiring the loads of customers that do not receive the LDD. *Id.* BPA agrees that LDD benefits should not be used as a means to acquire new load and should benefit only those consumers on a purchaser's distribution system. *Id.*

BPA agrees with NRU's clarification that the Retail Access Exclusion will not apply to new service resulting from bypass, utility mergers, the annexation of territory, or the acquisition of territory by voluntary purchase agreement. NRU Brief, WP-02-B-NI-02, at 20. If the acquisition would have been allowed prior to Retail Access Legislation, then the gained load is still eligible for LDD benefits. Under the circumstances noted above, a utility would be allowed to receive the LDD as long as these actions were allowed prior to any Federal, state, or local retail access legislation.

PacifiCorp argues that BPA denied PacifiCorp's request to extend the LDD to its southern Idaho customers, while approving several proposals to extend or maintain benefits of the LDD that were proposed by BPA's preference customers. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5. First, BPA makes its decisions on each issue based on the merits of each issue, not on the party that raises an issue. BPA's reasons for the decisions noted by PacifiCorp are explained in detail elsewhere in this section. In addition, a number of these changes are available to benefit both IOUs and preference customers that are eligible for the LDD, *e.g.*, the retention of the Additional Adjustment for Very Low Densities and the withdrawal of the Benefits Legislation Exclusion.

PacifiCorp objects to BPA's proposal to extend eligibility to load gained through bypass or annexation of territory, so long as PacifiCorp's residential customers in southern Idaho are denied the benefits. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5. PacifiCorp notes that by allowing load gained through bypass or annexation to be eligible for the LDD, and by expanding LDD benefits to preference customers but not to the IOUs, the Administrator's decision may add an additional incentive to public power takeovers of IOUs' facilities. *Id.* BPA disagrees with PacifiCorp, in that the LDD benefits are not being expanded as PacifiCorp suggests. As noted above, NRU requested a clarification and cited examples of service territory expansions that are presently allowed and eligible to receive LDD benefits. NRU was concerned that BPA would apply the Retail Access Exclusion section to actions that are presently allowed. In agreeing with NRU's clarification, BPA will still enforce the Retail Access Exclusion section if the load gained would not otherwise have been gained absent legislation. BPA is not expanding the benefits beyond what is presently allowed.

<u>Decision</u>

BPA includes a Retail Access Exclusion in the LDD.

<u>Issue 8</u>

Whether and how BPA should apply the LDD to the Slice product.

<u>Parties' Positions</u>

Parties advocate the application of the LDD to the Slice product. PNGC raises an implementation issue. PNGC Brief, WP-02-B-PN-01, at 22-23. PNGC notes that, when there are few or no non-Slice LDD recipients in a given discount bracket, instead of using a $/MWh value for each discount bracket, a linear relationship among the discount brackets should be established based on data available from non-Slice LDD customers; PNGC proposes a refinement. *Id.*

BPA's Position

BPA proposed that the LDD be applied to the Slice product. Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5). BPA would determine a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible to receive the discount. *Id.* BPA would use billing data from the previous CY when calculating the dollars/MWh discount rate for Slice customers. *Id.* The rate would be applied to only that portion of Slice power being purchased that is requirements power. *Id.* In its rebuttal testimony, BPA proposed a number of refinements to this approach. The $/MWh value would be adjusted by percentage increases or decreases in the PF Preference rate. Gustafson *et al.*, WP-02-E-BPA-48, at 4. Also, when there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis rather than a constant term. *Id.* at 4-5.

Evaluation of Positions

In the Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5), BPA proposed that to be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 100. BPA proposed that the LDD benefit for Slice customers would be determined and applied as follows:

> By September of each year, BPA will establish a dollars/MWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The dollars/MWh discount rate for each bracket will be determined by using billing data of customers within the same LDD percentage bracket. Those customers' total dollars in LDD discounts received will be divided by eligible MWhs purchased. This will result in a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous Calendar Year when calculating the dollars/MWh discount rate for Slice customers.
>
> The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice true-up will include an LDD true-up if based on estimates. If it is based on after the fact monthly data, no true up is necessary.

See Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5).

PNGC argues that the use of previous CY data may falsely value the $/MWh value in years when BPA experiences a rate change (*i.e.*, third year of stepped-up rate, CRAC, and so on). PNGC Brief, WP-02-B-PN-01, at 22-23. *See* Thayer *et al.*, WP-02-E-PN-03, at 9. PNGC proposes that BPA should use previous CY data to estimate the $/MWh values, and at the end of the year BPA should use actual data to produce a final set of $/MWh. *Id.* BPA would then refund or bill any differences just like any other estimated bill. *Id.* In rebuttal testimony, BPA acknowledged that PNGC identified a legitimate concern. Gustafson *et al.*, WP-02-E-BPA-48, at 3-4. PNGC's proposal to treat the $/MWh value as an estimated amount and conduct a true-up at the end of the year is one approach to addressing this problem. *Id.* This approach, however, would place a greater administrative burden on BPA. *Id.* While there are some instances where it may be necessary, BPA would like to minimize the use of estimates and true-up practices in the implementation of BPA's rates. *Id.* An approach that would not impose this burden would be to adjust the $/MWh value by percentage increases or decreases in the PF Preference rate. *Id.* These increases or decreases would include changes in rates from the first three years of the rate period to the last two years of the rate period and the establishment of a new PF Preference rate. *Id.* This approach would not apply to increases due to the TAC, CRAC, or the DDC. *Id.* The reason BPA would not make an adjustment to the $/MWh value for these changes is because the Slice product and subsequent Slice rate are not subject to TAC, CRAC, or DDC. *Id.* Therefore, a change to the $/MWh value for those rate adjustments is not applicable. *Id.* By adjusting the $/MWh value by the percentage of a PF Preference rate increase or decrease, PNGC's concern regarding a "false value" is addressed, and a true-up would not necessary. *Id.*

In response to BPA's proposal, PNGC argues that it would accept BPA's alternative solution with the caveat that the percentage change in BPA's overall rates would not translate into identical percentages for individual customers. PNGC Brief, WP-02-B-PN-01, at 22. The only way for the percentage method to work would be for BPA to use the specific percentage change for each individual LDD-receiving utility. *Id.* For example, PNGC member utilities are actually receiving a rate increase from PF-96 to PF-02 because of changes in BPA's rate design, while the overall PF-96 to PF-02 revenues to BPA are stable. *Id.* at 22-23. Because of that anomaly, certain BPA customers receive rate increases, while BPA's overall rates remain stable. *Id.* at 23. BPA agrees with PNGC's solution to calculate the specific percentage change for each non-Slice utility receiving the LDD. When there is a PF rate change to energy, demand or load variance charge(s), BPA will calculate a new $/MWh rate using the previous year's energy and load data and the new rate(s). This calculation will be done for each individual non-Slice utility receiving the LDD and then averaged for each bracket the individual utility is in (*i.e.*, 0.5 percent to 7.0 percent LDD). This will result in a new $/MWh rate that reflects any rate changes.

PNGC argues that BPA proposes to determine a $/MWh value for each discount bracket, which may pose a problem if there are few or no non-Slice LDD recipients in a given discount bracket. PNGC Brief, WP-02-B-PN-01, at 23. *See* Thayer *et al.*, WP-02-E-PN-03, at 10. PNGC proposes that BPA determine a linear relationship among the discount brackets based on data available from the non-Slice LDD customers, possibly using a regression analysis and not a constant term. *Id.* The linearized $/MWh value for each discount bracket would be what was applied to the Critical Slice Amount to determine a Slice participant's LDD. *Id.* BPA would use previous CY data for the estimate and actual data for the final values. *Id.* In its rebuttal testimony, BPA acknowledged that PNGC has identified a legitimate concern. Gustafson *et al.*, WP-02-E-BPA-48, at 4-5. BPA agreed that, when there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis and not a constant term. *Id.* Use of previous year data is adequate for determining the $/MWh value and, as stated in the previous issue, BPA would increase or decrease the $/MWh value if a rate increase or decrease occurs in the year the discount is applied. *Id.* This would eliminate the need for later true-up calculations. *Id.*

PNGC argues that it does not object to the use of percentage increases for the value inputs as long as the data are gleaned on an individual LDD-eligible customer basis. PNGC, WP-02-B-PN-01, at 23. BPA proposed a number of refinements to this approach, including that the $/MWh value would be adjusted by percentage increases or decreases in the PF Preference rate to deal with possible rate changes. Gustafson *et al.*, WP-02-E-BPA-48, at 4. This issue is dealt with in Issue 9 below.

Decision

BPA will apply the LDD to the requirements portion of the Slice product using a calculation and adjustment for increases or decreases in the PF rate.

Issue 9

Whether energy rates alone should be used in calculating changes in the LDD due to changes in the PF rate.

Parties' Positions

PNGC argues that BPA should use the demand, load variance and energy components of the LDD applied to a non-Slice requirements customer to determine the percent change in the PF rate which then applies to the $/MWh LDD proxy. PNGC Ex. Brief, WP-02-R-PN-01, at 8-9.

BPA's Position

In the Draft ROD, BPA proposed to change the LDD amount applied to Slice in the event of a PF rate change using only the energy rates to calculate the percentage change in the PF rate. *See* Draft ROD, WP-02-A-01, at 10-76 through 10-78.

Evaluation of Positions

BPA proposed that the calculation of an increase or decrease in the PF rate would be a straight line percentage of the increase or decrease for each diurnal period identified in the HLH and LLH rate tables. Draft ROD, WP-02-A-01, at 10-77. Demand and load variance are not components of the Slice Product and therefore are not included in the equation. *Id.* PNGC argues that in the case of the LDD, the Draft ROD contains what appears to be an error. PNGC Ex. Brief, WP-02-R-PN-01, at 8-9. BPA has stated that it will change the LDD amount applied to Slice in the event of a PF rate change using only the energy rates to calculate the percentage change in the PF rate. *Id*. PNGC argues that this presents a false picture of any rate change. *Id*. BPA applies the LDD to Slice on a $/MWh basis because of the nature of the Slice product. *Id*. However, PNGC argues, for other non-Slice requirements customers, the LDD is given on demand, load variance and energy. *Id*. PNGC claims that to calculate changes in the LDD due to changes in the PF rate, it is necessary to calculate the LDD using all three components it is based on to non-Slice requirements customers. *Id*. PNGC notes that the $/MWh is only a proxy for full application because of the nature of the Slice rate. *Id*. PNGC notes that the allocation of costs between demand, load variance, and energy is a topic of much debate in any BPA rate case. *Id*. PNGC argues that using only energy may under- or over-state any PF rate change depending on the shift in allocation between the three components of the PF rate. *Id*. In this situation, PNGC claims, it will definitely understate any PF rate change for PNGC's members. *Id*. In summary, PNGC argues that BPA should use the demand, load variance, and energy components of the LDD applied to a non-Slice requirements customer to determine the percent change in the PF rate which then applies to the $/MWh LDD proxy. *Id*. BPA concludes that PNGC's arguments are well-reasoned. Changes in the PF rate will be calculated using all three PF rate components.

Decision

Changes in the LDD due to changes in the PF rate will be calculated using energy, demand, and load variance charges.

Issue 10

Whether BPA should allow qualification for the LDD to be calculated on a state-by-state basis when a multistate utility's retail rates within a state are based on a revenue requirement that contains only the costs of the utility's distribution facilities within that state.

Parties' Positions

PacifiCorp argues that its residential consumers in southern Idaho should be eligible for the LDD, because such customers are subject to higher rates due to low system densities and are presently ineligible for the LDD due to the higher system densities in Washington and Oregon. PacifiCorp Brief, WP-02-B-PL-01, at 3-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 1-2. PacifiCorp also argues that BPA should apply the LDD to both the RL rate and the PF Exchange Subscription rate. *Id.* at 7-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3-4.

NRU argues that PacifiCorp's consumers should not be eligible for the LDD because existing LDD benefits have been limited, the Subscription ROD precludes increases in LDD costs, and PacifiCorp's proposal would violate the Northwest Power Act. NRU Brief, WP-02-B-NI-02, at 20-23.

BPA's Position

BPA did not take a position, for purposes of the PF Exchange Program rate or the NR-02 rate, on whether the LDD should be calculated on a state-by-state basis based on a multistate utility's retail rates within a state. Gustafson *et al*., WP-02-E-BPA-48, at 7-8. BPA wanted to review the parties' briefs on this issue. *Id.* BPA proposed that the LDD should not apply to the RL-02 and PF Exchange Subscription rates. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10. In the Draft ROD, BPA proposed that the LDD should not be calculated on a state-by-state basis based on a multistate utility's retail rates within a state. Draft ROD, WP-02-A-01, at 10-78 through 10-84.

Evaluation of Positions

PacifiCorp argues that its customers in southern Idaho currently pay retail rates that are adversely affected by high distribution costs resulting from low system density in its sparsely populated Idaho service territory. PacifiCorp Brief, WP-02-B-PL-01, at 3. PacifiCorp notes that its customers are ineligible for the LDD because BPA calculates the LDD by taking the average system density of all of a utility's service territories, which in some cases can be extensive and may include other states. *Id.* PacifiCorp argues that current application of the LDD criteria unfairly penalizes PacifiCorp's southern Idaho customers. *Id.* PacifiCorp's retail customers in southern Idaho bear the full cost of the low-density distribution system, because PacifiCorp has higher density and less expensive distribution systems in other Northwest states. *Id.* Yet under the principles of state utility regulation, distribution costs are location-based, and therefore retail customers in southern Idaho obtain no benefits from the utility's higher-density distribution systems in other states. *Id.*

PacifiCorp argues that there is a disconnect between how IOU retail rates are set and how BPA determines eligibility for the LDD. PacifiCorp Brief, WP-02-B-PL-01, at 4. PacifiCorp argues that the lower-cost, higher-density distribution systems in PacifiCorp's other jurisdictions are not available to offset the adverse impacts of the higher-cost, lower-density distribution system in Idaho. *Id.* Therefore, PacifiCorp's residential and rural consumers in Idaho lose a discount given to other retail consumers in low-density service territories. *Id.* PacifiCorp argues that BPA should revise the LDD to provide that "for multistate utilities that include in rate base only electric distribution costs related to distribution facilities situated in a particular state, BPA shall compile the data submitted by the Purchaser on a state-by-state basis and calculate the ratios on a state-by-state basis, for the Purchaser's entire electric utility system in the PNW . . ." PacifiCorp Brief, WP-02-B-PL-01, at 5.

In its rebuttal testimony, BPA recognized that PacifiCorp's lower-cost, higher-density distribution systems in PacifiCorp's other jurisdictions are not available to offset the adverse impacts of its higher-cost, lower-density distribution system in Idaho. Gustafson *et al.*, WP-02-E-BPA-48, at 7-8. BPA expressed concern, however, with two issues. *Id.* First, under the Northwest Power Act, the LDD is applied "in order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities." *Id.* Because the Act refers to "customers," BPA must determine the proper customer for application of the LDD. *Id.* On one hand, PacifiCorp is BPA's customer, even though it has jurisdictions in numerous states. *Id.* On the other hand, as PacifiCorp points out, the REP is implemented on a state jurisdictional basis, with PacifiCorp's Idaho service territory served by its Utah Division. *Id.*

Second, while the LDD is intended to avoid adverse impacts on retail rates of low-density customers, distribution costs are not the only costs that affect retail rates. *Id.* While lower-cost, higher-density distribution systems may not be available to offset the impacts of higher-density distribution systems, a large multistate utility might have economies of size or efficiencies in administration, resource planning, or other areas that might help to offset some of its higher distribution costs in its state jurisdictions. *Id.* A utility might have low retail rates despite higher than normal distribution costs. *Id.* BPA noted that it would like to review the parties' testimony and briefs on these issues to make an informed decision. *Id.*

PacifiCorp notes that BPA raised an issue regarding whether the Northwest Power Act's reference to customers meant PacifiCorp or PacifiCorp's customers, the residential and rural ratepayers of southern Idaho. PacifiCorp Brief, WP-02-B-PL-01, at 6. PacifiCorp acknowledges that the literal language of the statute may well refer to BPA's utility customers, but argues that retail ratemaking for IOUs is done on a state jurisdictional basis. *Id.* PacifiCorp argues that BPA should conclude that discounts should be offered to each retail jurisdiction with low system densities, and that it is illogical that Congress would intend for the LDD to be denied to a ratepayer based simply on whether his or her utility had operations in other states with higher densities and those higher densities provide no benefit to a ratepayer living in a low density region. *Id.*

NRU, on the other hand, argues that PacifiCorp's proposal would violate the Northwest Power Act. NRU Brief, WP-02-B-NI-02, at 22-23. NRU argues that section 7(d)(1) of the Northwest Power Act authorizes the Administrator to implement an LDD for "customers" with low system densities. *Id.* NRU argues that there is no reference in the Act to customers that have low densities in a portion of their system, nor is there the slightest hint in the Act, the legislative history, or in any BPA interpretation of the Act over the past 20 years that this provision was intended to be implemented on a state-by-state basis within the Northwest. *Id.* NRU argues that while the Northwest portion of a utility's service territory has been allowed to qualify for LDD benefits, even that program has never been implemented on a state-by-state basis; rather, the entire Northwest service territory of the utility has always been considered as a whole. *Id.* PacifiCorp's and NRU's arguments must be addressed by an examination of the Northwest Power Act and its legislative history.

PacifiCorp is a customer and purchaser of power from BPA. Pacific Power & Light and Utah Power & Light (UP&L) are simply business names of a single utility, PacifiCorp. BPA's GRSPs have required the determination of the LDD to be calculated using data based on "the Purchaser's entire electric utility system in the Pacific Northwest (PNW)." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99.

The Northwest Power Act supports the requirement that eligibility for the LDD is based on a customer's entire system within the region. Section 7(d)(1) of the Northwest Power Act provides BPA the discretionary authority to establish and implement the LDD:

> In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, *to the extent appropriate*, apply discounts to the rate or rates of such customers.

16 U.S.C. §839e(d)(1) (emphasis added).

The statutory language "to the extent appropriate" grants the Administrator great discretion in determining eligibility for the LDD. Even ignoring this discretion, however, the language of the Northwest Power Act is quite clear. The Northwest Power Act allows the Administrator to apply discounts to the rates of customers with low system densities. PacifiCorp acknowledges that the literal language of the statute may well refer to BPA's utility customers. PacifiCorp Brief, WP-02-B-PL-01, at 6. Under the plain meaning of the Act, the LDD is applied to the customer as a whole and not some part of a customer. *See* NRU Brief, WP-02-B-NI-02, at 22-23. Notably, the statutory language also references "low *system* densities." The plain meaning of this language is that the customer's entire system must be reviewed in determining eligibility for the LDD. PacifiCorp is a single customer. PacifiCorp has a large integrated system within the PNW region. For these reasons, PacifiCorp's entire system within the region must be used in determining eligibility for the LDD. This conclusion is also consistent with the legislative history of the Northwest Power Act.

The legislative history of the Northwest Power Act demonstrates that Congressional intent in establishing the LDD was to benefit rural electric cooperatives with high distribution costs. The purpose of the LDD is described in the report of the House Committee on Interior and Insular Affairs:

> Section 7(d)(1) permits BPA to offer rate discounts to customers with low system densities such as rural electric cooperatives with high distribution costs resulting from sparsely populated service areas.

H.R. Rep. 976, Pt. I, 96th Cong., 2d Sess. 52 (1980).

The report of the House Committee on Interstate and Foreign Commerce similarly provides:

> Section 7(d) permits the Administrator to apply constraints to the rates of customers with low system densities. This is intended to afford greater equity to consumers of small rural co-ops which have high distribution costs due to difficult terrain, remote service areas, or other factors.

H.R. Rep. 976, Pt. II, 96th Cong., 2d Sess. 69 (1980).

An immense utility such as PacifiCorp can be eligible for the LDD if it meets the LDD criteria, but those criteria must be based on the utility's entire regional system. PacifiCorp argues that in the REP, BPA recognizes that benefits must be based on an Average System Cost (ASC) that is calculated on a state-by-state basis, based on the costs that are actually used in the determination of retail rates within each state. PacifiCorp Brief, WP-02-B-PL-01, at 4. In its rebuttal testimony, BPA acknowledged that PacifiCorp correctly noted that Residential Exchange benefits are determined on a state-by-state basis, based on a comparison of the utility's ASC with BPA's PF Exchange rate. Gustafson *et al.*, WP-02-E-BPA-48, at 8. The REP, however, is a different program than the LDD. Compare 16 U.S.C. §839c(c) with 16 U.S.C. §839e(d)(1). Simply because a program established in the Northwest Power Act determines benefits on a state-by-state basis based on the utility's costs in each state does not require that the LDD be applied in the same manner. One must review the nature and intent of the LDD to determine its proper application. Utility divisions are not separate utility customers but rather are divisions of a single utility customer. While the REP may be implemented based on state retail ratemaking jurisdictions, the LDD applies to utility customers, not divisions of utility customers. The issue is not whether a utility has different divisions serving different service territories, but whether the service territories are served by different utility customers. PacifiCorp wishes to impose the REP upon the determination of eligibility for the LDD. To the contrary, however, the LDD is provided to customers based only on each customer's entire regional system. While the REP may distinguish among divisions and portions of service territories, the same standards do not apply to the LDD, which looks at a customer's entire system within the region in all state jurisdictions for all divisions. For purposes of LDD determination, PacifiCorp is the purchaser for all power it purchases from BPA, not any PacifiCorp division.

In its brief on exceptions, PacifiCorp notes BPA's argument that "under the plain meaning of the [Northwest Power] Act, the LDD is applied to the customer as a whole and not some part of a customer . . . ." PacifiCorp Ex. Brief, WP-02-R-PL-01, at 2. PacifiCorp also notes that in referring to the statutory language referencing "low system densities," BPA concludes that "the plain meaning of this language requires consideration of a customer's 'entire system,' in determining eligibility for the LDD." *Id*. PacifiCorp argues that nowhere in the Northwest Power Act is the term "system" defined in reference to the statutory language referring to "low *system* densities." *Id*. PacifiCorp also argues that "system" does not have a single unambiguous meaning or even a plain meaning in the statutory context. *Id.* at 2-3. PacifiCorp is correct that the Northwest Power Act does not expressly define the term "system." However, BPA believes that the term "system" does have a plain meaning in the statutory context of the LDD. As noted previously, section 7(d)(1) of the Northwest Power Act refers to "the Administrator's *customers* with low system densities." 16 U.S.C. §839e(d)(1) (emphasis added). BPA believes that the logical meaning is that the statute is referring to an entire customer and thus the customer's entire system. PacifiCorp argues that it is only through legislative history that one learns the concern Congress is addressing is "high distribution costs." *Id*. Therefore, PacifiCorp argues that it is more reasonable to consider distribution system on a state-by-state basis where retail rates are calculated on that basis rather than to assume otherwise. *Id*. While it is true that the legislative history of the Northwest Power Act refers to "high distribution costs," it also consistently refers to "*small rural co-ops* which have high distribution costs due to difficult terrain, remote service areas, or other factors" and to "*rural electric cooperatives* with high distribution costs resulting from sparsely populated service areas." H.R. Rep. 976, Pt. I, 96th Cong., 2d Sess. 52 (1980) (emphasis added); H.R. Rep. 976, Pt. II, 96th Cong., 2d Sess. 69 (1980) (emphasis added). Such small rural cooperatives would have the LDD applied to their entire cooperative and their entire system. While multistate utilities would still be eligible for the LDD, they must similarly qualify on their entire utility and their entire system. BPA believes it would not be appropriate to permit eligibility for the LDD based on state-by-state jurisdictions of a customer.

PacifiCorp also argues that the Northwest Power Act does not compel the limitation on eligibility for the LDD proposed by the Administrator. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3. PacifiCorp argues that the explicit directive of Congress is that the Administrator apply discounts "[i]n order to avoid impacts on retail rates of the Administrator's customers with low system densities." *See* 16 U.S.C. §839e(d)(1). *Id*. PacifiCorp argues that this directive is more appropriately implemented by designing a program that makes the benefits of discounted Federal power to all retail customers that pay rates based on high distribution costs. *Id*. PacifiCorp argues that only by offering the discount to each retail jurisdiction with high distribution costs can the Administrator ensure that Congressional intent is carried out with respect to multistate utilities. *Id*. First, the statutory directive is that "[i]n order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, *to the extent appropriate*, apply discounts to the rate or rates of such customers."

16 U.S.C. §839e(d)(1) (emphasis added). As noted above, BPA believes that the Act allows multistate utilities to be eligible to receive the LDD, provided they meet the applicable criteria. These criteria, however, allow only *customers* with low density *systems* to receive the LDD. In the case of a large multistate utility, the utility may still receive the LDD, it must simply do so by establishing a low system density for its entire service territory. In this manner, Congressional intent is satisfied because the LDD is available for multistate utilities that have low density systems for their entire system based on that system's overall high distribution costs.

PacifiCorp also notes that BPA questioned whether a large multistate utility might have certain economies of scale that would offset high distribution costs. PacifiCorp Brief, WP-02-B-PL-01, at 7. PacifiCorp notes that BPA did not investigate this proposition and did not consider whether preference customers might have cost advantages over IOUs that would offset their high distribution costs. *Id.* PacifiCorp argues that BPA should not look at these criteria if not set forth in the Northwest Power Act. *Id.* NRU argues that BPA pointed out that large multistate utilities such as PacifiCorp may realize economies of scale, which may offset higher distribution costs in its state-by-state distribution systems. NRU Brief, WP-02-B-NI-02, at 23. In BPA's rebuttal testimony, BPA stated that "[a] utility might have low retail rates despite higher than normal distribution costs. BPA would like to review the parties' testimony and briefs on these issues to make an informed decision." Gustafson *et al.*, WP-02-E-BPA-48, at 7-8. BPA therefore intended to review the parties' rebuttal testimony and briefs on this issue to determine whether there was evidence that this was a factor that should be considered. BPA found that the parties' rebuttal testimony did not address this issue, and the briefs provided no new evidentiary information. Because there is an insufficient record in the current rate case to make a determination on this issue, BPA will not consider this issue in determining eligibility for the LDD. This issue may be addressed in future rate cases. BPA, however, disagrees with PacifiCorp's contention that BPA should not look at criteria if not set forth in the Northwest Power Act. BPA is using the criteria set forth in the Northwest Power Act, but in determining the applicability of those criteria, it is appropriate to review evidence regarding such factors. In this case, the statute refers to "*adverse impacts on retail rates* of the Administrator's customers with low system densities." 16 U.S.C. §839e(d)(1). In the event there are factors that offset adverse impacts on retail rates, such factors may be reviewed in future proceedings.

NRU argues that BPA should reject PacifiCorp's proposal for state-by-state LDD eligibility. NRU Brief, WP-02-B-NI-02, at 20-23. NRU argues that the Subscription ROD precludes increases in LDD costs. *Id.* at 21. In developing the Subscription Strategy, NRU argues that BPA deferred its proposal to eliminate the K/I ratio from the LDD but rejected any increase in the 7 percent cap, noting that "BPA has indicated its intent to control future LDD costs . . . [A]ny increase in the LDD would be contrary to this effort." *Id.* NRU also argues that PacifiCorp should have raised its proposal during the Subscription process. *Id.* at 21-22. NRU also argues that it would be unfair for BPA to create a new LDD benefit for PacifiCorp while telling other utilities that it wants to cap or reduce benefits. *Id.* at 22. NRU misinterprets the Subscription ROD. BPA's statements in the Subscription Strategy and ROD were not final rate decisions, which can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal, which then might be subject to change in the formal hearing. Therefore, the Subscription ROD does not preclude the adoption of PacifiCorp's proposal if BPA determined that such proposal were appropriate.

PacifiCorp argues that the LDD should be available to the RL and PF Exchange Subscription rates. PacifiCorp Brief, WP-02-B-PL-01, at 7-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3-4. PacifiCorp argues that the Subscription Strategy expressly provided for parity between the PF and RL rate. *Id.* The Subscription Strategy states that "These [IOU] sales will be at a rate approximately equal to the PF Preference rate, subject to establishment in BPA's rate case and consistent with BPA's rate directives." *Id.* PacifiCorp also argues that BPA witness Leathley acknowledged that in comparing the rate charged to two different customer classes, one must consider rates, terms and conditions of each offer to determine whether customers will pay approximately the same rate; thus, unless the RL rate receives the LDD, it will not be approximately equal to the PF Preference rate. PacifiCorp Brief, WP-02-B-PL-01, at 8; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 4.

PacifiCorp has misinterpreted BPA's Subscription Strategy. First, BPA's statements in the Subscription Strategy and ROD were not final rate decisions, which can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal, which then might be subject to change in the formal hearing. The Subscription Strategy did not specifically address, much less conclude, whether the LDD would apply to the RL rate. Significantly, BPA's statement noted that the RL rate was "subject to establishment in BPA's rate case and consistent with BPA's rate directives." This clearly recognized the possibility that the LDD might be determined in the rate case not to apply to the RL rate. It also recognized the possibility that BPA's rate directives might not require or permit the application of the LDD to the RL rate. Furthermore, BPA's general statement that IOU settlement sales will be at a rate "approximately equal to the PF Preference rate" (subject to the above-noted conditions) does not require the application of the LDD to the RL rate. The Subscription Strategy spoke in general terms about the level of the RL and PF Preference rates. The Subscription Strategy did not say that the RL rate would be eligible for the same rate adjustment features of the PF Preference rate. Indeed, this is consistent with the fact that the RL rate is not subject to a number of charges that apply to the PF Preference rate, such as the TAC, TACUL, SUMY, and other charges. Furthermore, in any event, an RL rate without the LDD would still be approximately equal to the PF Preference rate.

BPA believes it is inappropriate to apply the LDD to the RL rate for additional reasons. It is necessary to understand the nature of the sales governed by the RL and PF Exchange Subscription rates. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10. In BPA's Subscription Strategy, BPA proposed to offer regional IOUs the equivalent of 1,800 aMW of Federal power, in the form of power deliveries or monetary payments, to settle the utilities' rights to participate in the REP. *Id.* The RL and PF Exchange Subscription rates apply only to power sales and monetary benefit calculations under the proposed settlements. *Id.* In a separate administrative proceeding, BPA is developing a methodology for the allocation of the 1,800 [1,900] aMW benefits among the regional IOUs. *Id.* BPA is also taking public comment on whether the settlement amount should be increased from 1,800 aMW to 1,900 aMW. *Id.* As noted above, REP benefit calculations are based on the comparison of a utility's ASC with BPA's PF

Exchange rate. *Id.* These determinations are made for each individual exchanging utility. *Id.* These determinations do not affect the Residential Exchange benefits provided to other exchanging utilities. *Id.* Similarly, providing the LDD to an exchanging utility does not affect the Residential Exchange benefits provided to other exchanging utilities. *Id.* This is not true with regard to settlement benefits if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.*

BPA's settlement proposal allocates a specific amount of settlement benefits among a limited number of IOUs. *Id.* BPA solicited the views of the PNW state public utility commissions in order to develop its allocation proposal. *Id.* The commissions proposed specific amounts of the total benefits for each IOU, including specific amounts for each of PacifiCorp's three state jurisdictions. *Id.* BPA believes that the commissions' proposal was very difficult to develop. *Id.* BPA has no evidence that the commissions took into account the possible increase in benefits to PacifiCorp's Idaho jurisdiction if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.* If the LDD applied to those rates, only PacifiCorp would pay a lower rate for power provided under the proposed settlement agreements, and only PacifiCorp would receive an increased amount of monetary benefits due to a lower rate that, when compared with BPA's five-year market forecast, is used to calculate monetary benefits under the proposed settlements. *Id.* While the settlement amounts contained in the allocation proposal for other utilities would not be decreased, those utilities' percentages of the total settlement benefits would be reduced. *Id.*

In addition, on cross-examination BPA's witness noted additional reasons why the LDD should not apply to the RL and PF Exchange Subscription rates. BPA's witness stated that it would be inappropriate to apply the LDD to the RL rate for PacifiCorp's southern Idaho territory because BPA's initial proposal did not include LDD benefits going to any of the IOUs, and therefore when the state commissions developed a proposed allocation of settlement benefits among the IOUs, they would have not factored in the LDD in their calculations. Tr. 1520. In addition, BPA's witness noted that the commissions' proposed allocation to the UP&L division of PacifiCorp was practically the whole amount of its residential and small farm load. *Id.* To also provide the LDD to that load would have given preferential treatment to PacifiCorp's southern Idaho customers.

In its brief on exceptions, PacifiCorp argues that, while BPA points out that if the LDD were applied to the RL or PF Exchange Subscription rate, PacifiCorp would pay a lower rate for power to serve southern Idaho than other RL or PF Exchange Subscription customers pay, but this is basically the same as BPA's preference customers with low density systems paying a lower rate for power than preference customers with higher density systems. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 4. PacifiCorp also argues that "just as PacifiCorp's percentage share of the settlement benefits would rise if it qualifies for the LDD (and accepts a settlement offer), so too do preference customers qualifying for the LDD receive an increased percentage of federal power benefits as a consequence." *Id.* There is an important distinction that must be drawn between the RL and PF Exchange Subscription rates that apply to the proposed IOU Residential Exchange *settlements* and the PF Preference rate that applies to BPA's net requirements *sales* to preference customers. The PF Preference rate is a rate that BPA has applied for nearly 20 years for actual net requirements power sales to its preference customers.

The RL and PF Exchange Subscription rates, however, are rates that BPA is offering for the first time and for a single purpose: the settlement of the Residential Exchange Program. BPA's sales to preference customers are not limited to a defined amount of power. BPA's preference customers purchase power based upon their net requirements. In the proposed IOU settlements, however, there is a finite amount of benefits available to a limited number of utilities. In the Residential Exchange settlement proposal, BPA is attempting to treat all regional IOUs fairly. As noted previously, BPA's settlement proposal allocates a specific amount of settlement benefits among a limited number of IOUs. Gustafson *et al.,* WP-02-E-BPA-48, at 9-10. BPA solicited the views of the PNW state public utility commissions in order to develop its allocation proposal. *Id.* The commissions proposed specific amounts of the total benefits for each IOU, including specific amounts for each of PacifiCorp's three state jurisdictions. *Id.* BPA believes that the commissions' proposal was very difficult to develop. *Id.* BPA has no evidence that the commissions took into account the possible increase in benefits to PacifiCorp's Idaho jurisdiction if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.* Because the RL and PF Exchange Subscription rates apply only to the proposed Residential Exchange settlement agreements, and because BPA wishes to implement the settlements in a manner that is fair for all regional utilities and state regulatory commissions, BPA believes it would be inappropriate to apply the LDD to the RL and PF Exchange Subscription rates and alter the virtual regional consensus regarding the allocation of the settlement benefits among the individual regional IOUs.

In summary, the RL and PF Exchange Subscription rates are special rates for a specific purpose--the implementation of the proposed settlement agreements. Gustafson *et al*., WP-02-E-BPA-48, at 10. It is inappropriate to apply the LDD to these rates and indirectly affect the proposed percentage allocation of benefits provided to the potential settling utilities. *Id.*

Decision

BPA will calculate the LDD based on a customer's entire electric utility system within the region. The LDD will not be applied to the RL-02 and PF Exchange Subscription rates.

Issue 11

Whether BPA should clarify the rate schedules to which the LDD applies.

Parties' Positions

PacifiCorp argues that BPA should apply the LDD to both the RL rate and the PF Exchange Subscription rate. PacifiCorp Brief, WP-02-B-PL-01, at 7-9.

BPA's Position

In its initial proposal, BPA identified the following rate schedules as eligible for the LDD: the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. Gustafson and Thompson, WP-02-E-BPA-23, at 2-3. In its rebuttal testimony, BPA proposed that the LDD not apply to the RL-02 rate and the PF Exchange Subscription rate. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10.

<u>Evaluation of Positions</u>

In the initial proposal, BPA stated that the LDD would be applied to specified power purchases under the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. Gustafson and Thompson, WP-02-E-BPA-23, at 2-3. As discussed in the previous Issue, however, BPA has determined that it is not appropriate to apply the LDD to the RL-02 rate and the PF Exchange Subscription rate. The RL and PF Exchange Subscription rates are special rates for a specific purpose--implementation of the proposed settlement agreements. Gustafson *et al*., WP-02-E-BPA-48, at 10. It is inappropriate to apply the LDD to these rates and indirectly affect the proposed percentage allocation of benefits provided to the potential settling utilities. *Id.*

<u>Decision</u>

To clarify, the LDD shall apply only to the PF Preference rate, the PF Exchange Program rate, and the NR-02 rate.

10.13 <u>Conservation and Renewables (C&R) Discount</u>

BPA proposed the C&R Discount to create incremental efficiency gains and renewable energy supplies, and to provide incentives to continue the region's progress in low-income weatherization programs. Esvelt *et al*., WP-02-E-BPA-33, at 2. The C&R Discount is a line item reduction in the customer's monthly power bill. *Id*. at 5. The monthly discount will be set prior to the rate period based on the customer's Subscription power purchases. *Id*. The discount will be deducted as a dollar amount and will not affect calculation of other billing factors. *Id*. The amount of the C&R Discount is 0.50 mills/kWh of power purchases made from selected BPA rate schedules. *Id*. at 6.

<u>Issue 1</u>

Whether BPA should eliminate the incremental spending requirement under the C&R Discount.

<u>Parties' Positions</u>

PPC argues that BPA should eliminate the incremental spending requirement. PPC Brief, WP-02-B-PP-01, at 39-40. In its brief on exceptions, PPC claims that BPA unreasonably and arbitrarily rejected PPC'S recommendation to eliminate the incremental spending requirement. *See* Draft ROD, WP-02-A-01, at 10-88. BPA should reconsider and eliminate the incremental spending requirement of the C&R Discount. PPC Ex. Brief, WP-02-R-PP-01, at 8.

The DSIs argue that the Administrator should apply the C&R Discount to all conservation and renewables expenditures. DSI Brief, WP-02-B-DS-01, at 79. They claim that the Draft ROD's refusal to apply the C&R Discount to all conservation and renewables expenditures is arbitrary, capricious, and bad policy. DSI Ex. Brief, WP-02-R-DS-01, at 12.

Renewable Northwest opposes efforts to eliminate the incremental spending requirement. Renewable Northwest Brief, WP-02-B-RN-01, at 1.

NEC/SOS argue that BPA should require utilities to meet one of three specific tests to establish acceptable incremental investments that it recommended in its direct testimony. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 21.

BPA's Position

Incremental spending is intended to be a tool to measure the amount of the C&R Discount being spent on qualifying expenditures. Esvelt *et al*., WP-02-E-BPA-55, at 2. The utility will make its own decisions regarding the amount of its spending absent the C&R Discount and will determine its priorities on individual measures or projects. *Id*.

BPA evaluated and rejected the NEC/SOS recommended incremental spending proposal in BPA's rebuttal. *See* Esvelt *et al*., WP-02-E-BPA-55, at 6-7.

Evaluation of Positions

PPC argues that the incremental spending requirement is objectionable for several reasons. PPC Brief, WP-02-B-PP-01, at 39. PPC contends that incremental spending was first suggested by BPA in the spring of 1999 after the close of a public process. *Id*. PPC claims that it understood the use of the term "new" to apply singularly to "new renewable resources," but not to conservation resource expenditures. *Id*. PPC also argues that although BPA's Subscription Strategy ROD discussed that the C&R Discount would not be used to cover past investments, the Subscription ROD does not reflect the contemporaneous regional Subscription discussions. PPC's representatives participating in the Subscription proposal discussions do not recall even one discussion on this issue. *Id*. at 40. Finally, PPC argues that the incremental spending requirement decreases the flexibility available to BPA's public agency customers in designing conservation programs for their consumers. This would diminish the C&R Discount's value. *Id*.

The DSIs also oppose the incremental spending requirement and state that the discount should apply to all conservation and renewables expenditures. DSI Brief, WP-02-B-DS-01, at 79. The DSIs argue that the incremental requirement is inconsistent with the original policies underlying the recommendations of the Steering Committee to the Comprehensive Review. *Id*. at 78. In support of their position, the DSIs quote an argument made by NRU that "disqualifying otherwise qualified expenditures on the grounds that they are not 'incremental' would penalize the utilities that are presently making the most effort to implement conservation and renewable programs." *Id*.; *see* Saven, WP-02-E-NI-04, at 20. The DSIs argue that, similarly, the incremental investment is not consistent with the decision making progress of industrial consumers for whom investments are judged by management taking into account all of the costs and benefits known to exist at the time the decisions are made. DSI Brief, WP-02-B-DS-01, at 78. The DSIs are concerned that BPA might be tempted to discriminate between utilities and DSIs on the question of incremental investment. Waddington, WP-02-E-DS-05, at 5. The DSIs argue that customers should receive discounts on an equal basis for equal investments. DSI Brief, WP-02-B-DS-01, at 78. The DSIs note that BPA's willingness to expand its current exceptions to the incremental requirement to treat spending that qualifies under state mandated or state programs (whether the spending is by a DSI, a utility, or a utility's customer) ameliorates the problem of the incremental requirement somewhat and is a welcome step in the right direction. *Id*. at 79.

The parties' arguments are not persuasive. As cited by the PPC, BPA's Power Subscription Strategy ROD at 138 discussed the concern that the "C&R Discount not be used to cover the conservation and renewable resource investments that are already in power customers' plans." BPA's expert witnesses testified that BPA's decision to include incremental spending in the C&R Discount was publicly known prior to its proposal in this rate case. Esvelt *et al*., WP-02-E-BPA-55, at 3. BPA had a strong desire that the C&R Discount amount be supplemental to the amount power customers were planning to spend on these types of activities, *e.g.,* incremental conservation and renewable resource investments. *Id*. PPC opposes the incremental spending requirement because of concern that it would impact local control. Fey *et al*., WP-02-E-PP-05, at 4-5. The ability of customers to self-certify should alleviate some the concerns raised by the PPC regarding implementation of the C&R Discount. The utility will make its own decisions regarding the amount of its spending absent the C&R Discount and will determine its priorities for spending on individual measures or projects. Esvelt *et al*., WP-02-E-BPA-55, at 3.

Renewable Northwest argues that, even with the incremental investment requirement, utilities can still make investments in conservation and renewable resources that cater to their own service territories and are consistent with the needs of their own end-use customers. Renewable Northwest Brief, WP-02-B-RN-01, at 2. BPA agrees. BPA is not persuaded by PPC's statement that the incremental spending requirement will diminish the value of the C&R Discount. Making available a rate discount to customers purchasing firm power in Subscription is appealing, because it will allow utilities to design and implement conservation or renewables programs to respond to local circumstances, interests, and needs. Esvelt *et al*., WP-02-E-BPA-33, at 5.

The DSIs argue that the incremental spending requirement is inconsistent with the Comprehensive Review. DSI Brief, WP-02-B-DS-01, at 77. The concept for the C&R Discount is related to the Comprehensive Review's recommendation to Northwest states to sustain conservation and renewable resources development and low-income weatherization. Esvelt *et al*., WP-02-E-BPA-33, at 4. The Comprehensive Review does not, however, dictate how BPA is to design and offer the C&R Discount.

The DSIs also are concerned that the incremental spending requirement is not consistent with the decisionmaking process of industrial consumers. Waddington, WP-02-E-DS-05, at 6. While BPA is certainly sympathetic to its customers' decisionmaking processes, BPA has decided upon a mechanism that can be uniformly implemented. The specific charge per MWh applied to a customer's forecasted Subscription power purchases will allow it to prepare fixed annual budgets for conservation and renewables expenditures that are equal to its eligibility for the C&R Discount. Esvelt *et al*., WP-02-E-BPA-33, at 6. BPA expects local utility management to self-certify C&R Discount expenditures in the same way they approve budgets and forecasts. Esvelt *et al*., WP-02-E-BPA-55, at 4. The customer is in a position to approve a certification statement based on its knowledge of past expenditures and approved annual budgets. *Id*. BPA objects to the DSIs' reference or implication that BPA might be tempted to use this type of mechanism to discriminate between utilities and DSIs. BPA will employ the same criteria to all customers. Finally, BPA would like to correct a misstatement in the DSIs' initial brief. The DSIs view BPA's willingness to expand its current exemptions to the incremental requirement to treat spending that qualifies under state mandated or state programs (whether the spending is by a DSI, a utility, or a utility's customer) as a "welcome step in the right direction" to help ameliorate the problem of the incremental requirement. DSI Brief, WP-02-B-DS-01, at 79. The DSIs reference testimony of BPA's witness. Tr. 1636. BPA would like to clarify that BPA does not intend the exemption for purposes of state and municipal programs to include a "utility's customer." On redirect, BPA's witness corrected his testimony to make it clear the exemption applies to only a BPA customer. Tr. 1646.

PPC argues that, if BPA implements the incremental spending requirement, self-certification, and an exemption for those utilities who spend 3 percent or more of their revenues on public purposes is necessary. PPC raised the same issue in its direct case. BPA responded that it agreed that a utility which spends at least 3 percent of its retail revenues on qualifying measures should be exempt from the requirement that it certify that its expenditures are incremental. Esvelt *et al*., WP-02-E-BPA-55, at 3-4. PPC raises concern that BPA not adopt the stringent qualification standards for the incremental spending requirement proposed by the NEC in Weiss, WP-02-E-NA-01, at 22. PPC Brief, WP-02-B-PP-01, at 40. These incremental qualification standards would require utilities that do not invest more than 3 percent of retail sales in C&R Discount eligible activities to increase spending over a average amount based on the previous three years or any funding in excess in 1 percent of retail revenues.

In its brief on exceptions, NEC objects to BPA's conclusion in the Draft ROD that discounted the NEC's proposed recommendation for incremental spending. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 21. NEC/SOS claim that BPA's reasons for rejecting its proposal "make little sense and are contradictory." *Id.* NEC/SOS take out of context BPA's rebuttal testimony to argue that BPA admits that the NEC/SOS proposal "may have the advantage of being measurable." *Id*. The entire sentence of the BPA witnesses' testimony shows a well-reasoned decision regarding the NEC/SOS proposal. After reviewing and evaluating the NEC/SOS proposal, BPA's witnesses stated: "Although the first two paths suggested for determining whether a utility's investments in conservation and renewables are incremental may have the advantage of being measurable, they may also have unintended consequences." Esvelt *et al*., WP-02-E-BPA-55, at 6.

NEC/SOS now challenge BPA's rebuttal without having raised their arguments in their initial brief. NEC/SOS argue that BPA simply mischaracterizes the NEC/SOS proposal in order to discount it. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. In support of its recommended proposal, NEC/SOS counter that utilities might reduce their current spending levels in order to demonstrate an increase during the rate period. *Id*. at 21. NEC/SOS claim that this is equally true about BPA's own proposal, so it must not be given any more weight than NEC/SOS's. *Id*. NEC/SOS note that BPA states that the 1 percent path might be onerous to customers currently spending very little on conservation and renewables. *See* Esvelt *et al*., WP-02-E-BPA-55, at 7; NEC/SOS Ex. Brief, WP-02-R-NA/SA-01 at 21. NEC/SOS claim that their proposal allows these utilities to choose the other path, where their incremental spending is measured against previous levels, and allows those customers to qualify under that path. *Id*. at 21-22. BPA disagrees that it mischaracterized the NEC/SOS proposal in order to discount it, as alleged by NEC/SOS. The NEC/SOS attempt to rehabilitate its previous testimony is not persuasive. BPA's decision not to adopt the NEC/SOS proposed recommendation is well-reasoned and supported by substantial evidence.

BPA maintains that the first path could lead utilities to actually decrease their spending levels during the 2000-2001 time period in order to demonstrate an increase in spending during the rate period. Esvelt *et al*., WP-02-E-BPA-55, at 6-7. Using an earlier period, such as 1997-1999, would not work, because BPA's traditional conservation programs were operating during that time. *Id*. The second path proposes an arbitrary level of 1 percent as a base for determining incremental investments. *Id*. This level may have the unintended consequence of discouraging many utilities from increasing their C&R investments and participating in the C&R Discount at all. *Id*. BPA still believes that the NEC/SOS proposed recommendation may have unintended consequences which are not acceptable and contrary to BPA's stated desire to provide local control and administration of future conservation and renewable development activities. Esvelt *et al*., WP-02-E-BPA-55, at 6-7.

BPA does not agree that it is arbitrary, capricious and, as alleged by the DSIs in their brief on exceptions, bad policy to reject any parties' recommendation. PPC Ex. Brief, WP-02-R-PP-01, at 8; DSI Ex. Brief, WP-02-R-DS-01, at 12. BPA's decisions are based on the evidence in the record and are well reasoned and analyzed.

Decision

BPA will not eliminate the incremental spending requirement under the C&R Discount; the incremental spending requirement will measure the amount of the C&R Discount being spent on qualifying expenditures.

Issue 2

Whether BPA should modify the C&R Discount to allow the continuation of funding for low-income weatherization programs.

Parties' Positions

NEC and SOS propose that BPA modify the C&R Discount in a manner that would allow for the guaranteed future funding of low-income weatherization programs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. The NEC direct testimony criticized how BPA's proposed C&R Discount program dealt with low-income weatherization. Weiss, WP-02-E-NA-01, at 23. NEC/SOS provided details of their recommendation that BPA budget $4 million annually of C&R Discount funds to state low-income weatherization programs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 34, citing WP-02-E-NA-06. NEC and SOS urge BPA to replace its proposal with that of NEC. *Id*. at 35.

In their brief on exceptions, NEC/SOS note that they believe the decision in the Draft ROD is unclear. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. NEC/SOS argue that the decision in the Draft ROD is not a decision, and that they are unfairly precluded from supporting or opposing BPA's decisions based on the record or being able to correct the record regarding BPA's decision. *Id*. NEC/SOS go on to "correct one assumption" BPA makes, and that is the assumption about "local control," which BPA believes is increased by allowing its customers to direct the funds rather than what BPA characterizes as the "centralized funding" approach NEC/SOS proposed. *Id*. at 23.

<u>BPA's Position</u>

A central goal of the C&R Discount is to promote local control and management of conservation and renewable programs. Esvelt *et al*., WP-02-E-BPA-55, at 8. Central allocation of a portion of the C&R Discount to the states for low-income weatherization would result in a loss of local control. *Id*. at 7. BPA also stated this concern in cross-examination. *See* Tr. 1627. Central allocation of a portion of the C&R Discount to states for low-income weatherization would negatively impact utilities that wished to make all their investments in, for example, renewables. Tr. 1628.

<u>Evaluation of Positions</u>

BPA does not agree that the Draft ROD decision is unclear; however, BPA does recognize the need to clarify the evaluation of the parties' position in the Draft ROD regarding the funding of low-income weatherization programs. The NEC/SOS brief on exceptions targets only the "local control" aspect of BPA's decision because, as claimed by NEC/SOS, "[I]t is unclear, . . . what the Draft Decision actually says." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. In their initial brief, NEC/SOS urged BPA to replace its proposal with NEC's recommendation. NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. NEC's direct testimony criticized how BPA's proposed C&R Discount program dealt with low-income weatherization. Weiss, WP-02-E-NA-01, at 23. NEC proposed that BPA budget $4 million annually of C&R Discount funds for state low-income weatherization programs. WP-02-E-NA-06. NEC/SOS urged BPA to replace its proposal with that of NEC. NEC/SOS Brief, WP-02-B-NA/SA-01, at 35. BPA opposed NEC's recommended improvements for backup funding of low-income weatherization, because they are incompatible with BPA's goals for local control and management of the C&R Discount. Esvelt *et al*., WP-02-E-BPA-55, at 8. BPA does not accept the NEC proposal for central allocation of a portion of the C&R Discount to the states for low-income weatherization, also because of the loss of local control. Tr. 1628.

NEC/SOS contend that BPA has presented no evidence in this proceeding to demonstrate that the "local control" of DSIs and utilities is superior in any way to that of the community action agencies which currently run these programs and would continue to do so under NEC's proposal. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 23. NEC/SOS claim that it is arbitrary and capricious for BPA to use the concept of local control as a factor in choosing among alternatives without providing a meaningful definition and evidence on the record to support its conclusion. *Id*. at 24.

BPA recognizes the potential damage to current programs caused by funding uncertainties inherent in the proposed utility-by-utility funding mechanism. Tr. 1628-29. BPA has reviewed centralized funding, as discussed in cross-examination, to preserve the benefits of the existing low-income weatherization infrastructure. Tr. 1629-30. Centralized funding would reduce BPA financial risk liabilities and would provide continuous funding for state-run low-income weatherization activities. Tr. 1628-29. To implement this option, BPA has evaluated the amount of funding required to adjust existing budgets sufficient to continue the existing state low-income weatherization activities.

While recognizing the advantages and disadvantages of centralized funding, BPA favors the degree of local control provided by its proposed C&R Discount approach. NEC/SOS are mistaken in its understanding that BPA's decision is based solely on the concept of local control. BPA's decision is based upon reasoned analysis and evidence presented on the record throughout this rate proceeding. NEC/SOS are remiss in their failure to consider the entire record. In short, BPA stated in direct testimony that BPA made the policy decision to review regional C&R Discount annual spending levels for low-income weatherization. Esvelt *et al*., WP-02-E-BPA-55, at 8. BPA expects regional spending to amount to $4 million for low-income weatherization. *Id*. If this level is not reached, BPA will make direct investments in low-income weatherization to make up the shortfall. *Id*.

Decision

BPA will consider an alternative outside of the C&R Discount to continue funding low-income weatherization programs. BPA has already stated it would make good the funding.

10.13.1 Conservation Augmentation

Issue

Whether BPA has properly calculated the amount of conservation augmentation required to meet the NWPPC's current cost-effective conservation target.

Parties' Positions

NEC/SOS argue that conservation for augmentation is incorrectly calculated and should not include the C&R Discount, because it does not meet the Council's Plan. NEC/SOS Brief, WP-02-B-NA/SA-01, at 32. NEC/SOS argue that BPA is required to acquire 150 aMW from BPA-sponsored conservation activities. *Id*. NEC/SOS also argue that the correct number is 166 aMW in BPA's utilities' territories plus another 140 aMW for BPA's share of the DSI load, or a total of 306 aMW, not 150. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01 at 25**.**

PPC supports BPA's overall conservation goal of 150 aMW; it includes demonstrable savings implemented through the C&R Discount Program. PPC Brief, WP-02-B-PP-01, at 41.

BPA's Position

This is a new issue not raised previously by any parties to this proceeding. BPA has no position on this issue on the record. NEC/SOS's introduction of new conservation target numbers in their brief on exceptions is clearly unsupported by the record, nor does it comport with NEC/SOS's position as presented in their initial brief. As such, NEC's new argument is in violation of §1010.13 of the rules of procedure that govern this proceeding.

Evaluation of Positions

NEC/SOS argue that at the 150 aMW target is incorrect because it does not contain the amount of cost-effective conservation that the NWPPC has identified in BPA's load base. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 25. NEC/SOS claim that the number is now 166 aMW for utilities and 140 aMW for DSI load, for a total of 306 aMW. *Id*. NEC/SOS previously supported the 150 aMW target by stating in their initial brief, "Since the 150 aMW target the Council established was Bonneville's load share of the total cost-effective conservation available in the region, BPA should not count conservation which does not result in a reduction of the agency's load toward the 150 aMW target." NEC/SOS Brief, WP-02-B-NA/SA-01 at 33.

NEC/SOS's brief on exceptions introduces new conservation target numbers that are clearly unsupported by the record and which do not comport with NEC/SOS's position as presented in their initial brief. NEC/SOS make this assertion without offering any evidentiary support underlying their newest claim. Putting aside the fact that NEC/SOS do not provide any evidence to support their claim, no parties in this proceeding, including BPA, have had the opportunity to review, analyze, or offer evidence or testimony to rebut NEC/SOS's claim. NEC/SOS's new argument is in violation of §1010.13 of the rules of procedure that govern this proceeding. Without some factual support in the record to support rejecting the current conservation target of 150 aMW and the assumptions that underlie it, it would be unreasonable for BPA to do so.

BPA stated its plans to implement a total of 150 aMW from all BPA-sponsored conservation activities over the rate period. Oliver *et al*., WP-02-E-BPA-45, at 8. BPA included an annual acquisition target of 12 aMW of conservation resources, on an annual basis, in its augmentation plans. *Id.* The 12 aMW target was set based on the current 1998 Northwest Conservation and Electric Power Plan. *Id.*

NEC/SOS note that BPA is allowing customers that buy only a part of their power from BPA ("partial requirements customers") to qualify for the discount based on conservation programs carried out in their entire territory. NEC/SOS Brief, WP-02-B-NA/SA-01, at 32. In its brief on exceptions, NEC/SOS contend that BPA mischaracterizes NEC/SOS's point. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 25. NEC/SOS's point is "partial requirements may claim credit under the C&R Discount for conservation which does not reduce BPA's load." *Id*. They point out that "those conserved MWs which do reduce BPA's load should not counted . . . ." *Id*. NEC/SOS claim, without any evidence in the record to support their claim, that "[a] substantial portion of BPA's power will we [sic] sold to partial requirements customers that have significant loads served from other resources than Bonneville." *Id*. NEC/SOS contend that conservation expenditures, and their resulting load reductions, made by customers purchasing only a portion of their requirements power from BPA may not result in a reduction in their power purchased from BPA because these reductions are likely to result in reductions in purchases from higher-priced resources. *Id.* at 33. NEC/SOS claim that doing a correct calculation of the conservation acquired from partial requirements customers under the C&R Discount would result in raising "the amount of conservation BPA must acquire under its augmentation program." *Id.* at 39.

The NEC/SOS argument is not supported by any evidence in the record. Rather, NEC/SOS make broad conclusions based on generalizations of fact. NEC/SOS asked a hypothetical question of BPA's witnesses regarding the application of the C&R Discount to partial requirements customers. Tr. 1632. The full testimony of BPA's witness is as follows:

> A. (Mr. Esvelt) I think the answer is yes, with two qualifications. One is that of course the utility must be making expenditures on eligible measures. And the second qualification is that the C&R Discount of course establishes a maximum amount of discount dollars that are available to that utility.

Tr. 1632.

BPA's witness answered that a partial requirements customer is eligible for the C&R Discount. With regard to NEC/SOS's statement that BPA should not count conservation which does not result in a load reduction, BPA has neither testified, nor is there evidence in the record, as to how the conservation achievement of individual utilities resulting from the C&R Discount will be combined to meet the 150 aMW target. As noted by NEC/SOS, BPA currently sells power to some customers that use their own resources. Sections 5(b)(1)(A) and (B) of the Northwest Power Act expressly provide that BPA's obligation to serve customers purchasing for their regional firm power load shall be reduced by the amount of resources customers use to serve their regional loads. Sections 4 and 6 of the Northwest Power Act also direct BPA to seek and achieve conservation. These provisions do not limit the Administrator from achieving conservation due to the purchasing or operational basis of any BPA customer. *See, generally,* 16 U.S.C. §839b and §839f. NEC/SOS make an additional unsupported conclusion when they state, "these utilities have a large incentive to use any conservation-induced load reductions to reduce their take from higher priced resources." NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. The record does not provide evidence as to the specific loads of customers that will purchase on a partial requirements basis or as to the amount of power such customers may buy from BPA. Nor does the record provide evidence as to the price of the resources NEC claims that partial requirements customers will reduce as a result of the C&R Discount. For these reasons, BPA cannot accept the NEC/SOS position with respect to the calculation of the 150 aMW as it pertains to the C&R Discount.

Decision

BPA has properly calculated the amount of conservation augmentation required to meet the NWPPC's current cost-effective conservation target.

10.14 Green Energy Premium

Previously, BPA provided customers the opportunity to purchase Environmentally Preferred Power (EPP) through surplus firm power sales under the FPS-96 rate schedule at negotiated prices. Because the continued availability of surplus firm power that is sold under the FPS-96 rate schedule is uncertain in the next rate period, BPA developed the Green Energy Premium (GEP) to meet future demand by customers interested in purchasing EPP under Subscription firm power sales contracts. BPA included the GEP in the initial proposal to provide a method for customers to purchase EPP during the FY 2002-2006 rate period. Esvelt *et al.,* WP-02-E-BPA-33, at 12.

The GEP is a pricing approach applied to customers that choose to designate any portion (0 to 100 percent) of their Subscription power purchases as EPP. Customers selecting the GEP will continue to receive system power deliveries from BPA. In addition, these customers will receive EPP production documentation showing that their GEP purchases have resulted in the delivery of EPP to the system. *Id.*

GEP purchases require a customer to commit a portion of its net requirements, served at a posted firm power rate, to service at the posted rate plus the GEP. This is done by designating any portion of the customer's Subscription power purchases as EPP. The GEP will be available to purchases made under the PF-02, IP-02, RL-02, and NR-02 firm power rate schedules. Subject to the availability of surplus firm power, sales of EPP under the FPS-96 rate schedule may be offered in the future. Esvelt *et al.*, WP-02-E-BPA-33, at 13.

The GEP will be negotiated and range from zero to $40/MWh depending on the specific resource types selected by each customer. The customer's power bill will have a new line item showing the elected EPP energy amount in MWh times the GEP. *Id.*

When the GEP is based upon existing BPA resources, BPA will incur no additional costs but will accrue additional revenues. Where the output of non-BPA resources is acquired to meet GEP requests, the GEP customer will pay all associated incremental costs. To the extent incremental GEP revenue is received, it will benefit BPA's customers at large. BPA forecasts no sales of EPP and thus no revenue from the GEP. Esvelt *et al.*, WP-02-E-BPA-33, at 14.

Because no party raised the issue of offering the GEP on brief, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3 51 Fed. Reg. 7611 (1986).

10.15 Targeted Adjustment Charge (TAC)

The TAC is a charge that is applied to the PF-02 firm power rate for customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. Arrington *et al*., WP-02-E-BPA-24, at 1. The TAC recovers costs that BPA may incur, over and above the applicable rate, to serve incremental requirements loads. *Id*. The TAC will apply to customers that purchase firm power requirements service under the PF-02 rate after the Subscription window closes; to customers that add load through retail access after the window closes, including load that was once served and returns under retail access; and to customers applying for service to replace their own firm resources. *Id.* at 2. When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. *Id.* at 3. The TAC will not apply to the PF Exchange Program rate, because the Residential Exchange Program determines exchange benefits for residential and small farm customers and does not actually deliver power. *Id.* at 2. The TAC also does not apply to the PF Exchange Subscription rate, because the Residential Exchange settlement is available only during the Subscription window. *Id.* The TAC also applies to the NR rate. Arrington *et al*., WP-02-BPA-49, at 5.

Issue 1

Whether the TAC is cost-based and results in a tiered PF rate that is discriminatory and unfounded in law.

Parties' Positions

PPC argues that BPA's policy decisions to serve nonpreference customers, which reduce the available FBS resources to serve preference agency loads, taken together with its proposed imposition of a TAC on certain preference agency loads, create tiered rates for preference agency customers. PPC Brief, WP-02-B-PP-01, at 25. PPC quotes and cites the following language from section 4(a) of the Bonneville Project Act: "the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives," 16 U.S.C. §832c(a); section 4(d) of the Bonneville Project Act, "[I]t is declared to be the policy of the Congress, as expressed in this chapter, to preserve the said preferential status of the public bodies and cooperatives herein referred to . . . ," 16 U.S.C. §832c(d); and section 7(b)(1) of the Northwest Power Act,

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the PNW, and loads of electric utilities under §839c(c) of this title. Such rate or rates shall recover the costs of that portion of the FBS resources needed to supply such loads until such sales exceed the FBS resources.

16 U.S.C. §839e(b)(1). *Id.* at 26.

PPC argues that taken together, the spirit of these statutes is to ensure that publicly and cooperatively owned preference customers are entitled to priority in the purchase of Federal power at cost. *Id.* at 26-27. PPC adds that these provisions, along with the protections afforded preference customers in section 7(b)(2) of the Northwest Power Act, provide those customers the right to purchase Federal power at BPA's lowest cost-based rate and that the TAC cannot be reconciled with BPA's statutory rate directives. PPC Ex. Brief, WP-02-R-PP-01, at 6.

OURCA argues that the TAC is inconsistent with the statutory mandate in section 7(b)(1) of the Northwest Power Act that rates must be cost-based for public preference customers. OURCA Brief, WP-02-B-OU-01, at 5.

ICNU argues that TAC limits access to firm power by charging preference customers when they place unanticipated, incremental loads on BPA during the FY 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8. ICNU suggests that TAC is a pricing tool designed to limit the amount of preference power available to BPA's public agency customers in violation of section 4(b) of the Bonneville Power Act.

BPA's Position

The TAC could potentially be applied to all preference customers purchasing firm power under the PF rate schedule. Arrington *et al.*, WP-02-E-BPA-24, at 3. The TAC is a charge that is applied to the PF-02 firm power rate for the customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. *Id.* at 1. The TAC recovers the costs BPA may incur, over and above the applicable rate, to serve incremental requirements loads. *Id.* at 1-2. The TAC will be calculated for an individual customer, upon request by the customer for PF service after the Subscription window closes, or for certain other unanticipated incremental loads. *Id.* When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. *Id.*

Evaluation of Positions

PPC contends that the TAC creates a tiered rate for Federal power service to preference agency loads. PPC Brief, WP-02-B-PP-01, at 24. PPC claims that BPA's decisions to serve nonpreference customers have had the effect of reducing the availability of the FBS resources to serve public agency loads. PPC further argues that despite that reduction, and BPA's legal obligation to supply preference customers with Federal power at cost, BPA's decision to apply the TAC is a continued refusal to implement the law. PPC Ex. Brief, WP-02-R-PP-01, at 6. As a result, PPC claims, market-based costs that preference agency loads would not otherwise bear will be imposed through TAC and through other related adjustments and charges for service from the FBS. PPC Brief, WP-02-B-PP-01, at 24. PPC maintains that the TAC is not in keeping with the spirit of applicable statutory preference provisions and section 7(b)(1) of the Northwest Power Act, 16 U.S.C. §839e(b)(1). *Id.* at 24. OURCA argues that the TAC is inconsistent with the statutory mandate in section 7(b)(1) of the Northwest Power Act that rates must be cost-based for public preference customers. OURCA Brief, WP-02-B-OU-01, at 5.

BPA does not dispute that public body and cooperative utility customers are entitled to preference and priority under BPA statutes. *See* 16 U.S.C. §832b and §832c(a). The statutory provisions cited by the PPC, OURCA, and ICNU, however, do not prohibit BPA from establishing the TAC as proposed. The TAC as proposed under section 7 of the Northwest Power Act is consistent with the preference and priority accorded to public body and cooperative utilities under the provisions of statute cited by these parties.

PPC's and OURCA's argument that the TAC is not cost-based appears to reflect the position that any power that BPA purchases from the market to serve preference agency customer load is not cost-based pursuant to section 7(b)(1) of the Northwest Power Act. 16 U.S.C. §839e(b)(1). Contrary to the parties' contention, however, the power purchased to meet the load that is subject to the TAC is FBS replacement power, Tr. 1101; the cost of which must be recovered consistent with section 7(b)(1) of the Northwest Power Act. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's costs included in the TAC to replace reductions in the capability of the FBS resources are the costs of FBS resources. The TAC is a charge that is applied to the PF-02 rate for customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. Arrington *et al.,* WP-02-E-BPA-24, at 1. Under BPA's broad authority to design its rates to recover its total costs to meet its revenue requirement, an adjustment charge such as the TAC is appropriate. 16 U.S.C. §839e(e). "In short, the statute does not require BPA to impose any particular type of rate on its customers. Rather, it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson,* 813 F.2d 1364 (9^{th} Cir. 1987). PPC also claims that TAC cannot be reconciled with the preference provisions in BPA's statutes and cites to section 7(b)(2) of the Northwest Power Act. PPC Ex. Brief, WP-02-R-PP-01, at 6. Contrary to PPC's claim, BPA is establishing its priority firm power rate as directed by section 7(b)(2). BPA's preference customers purchasing under the PF-02 rate are being afforded the appropriate rate protection as required under section 7(b)(2). *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05A, at 72 (*see e.g.,* RDS 30 and RDS 31). When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. Arrington *et al.*, WP-02-E-BPA-24, at 2.

Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal, or other rate forms.

16 U.S.C. §839e(e).

BPA's rates are certainly "cost-based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. Nevertheless, within the context of those directives, section 7(e) and its legislative history make clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Congress did not direct BPA to use specific rate structures or billing practices to show the cost of new power supplies. As a result, it was recognized that many provisions could lead to rate reforms. *See, e.g., Comptroller General of the United States, Comments on Pacific Northwest Power Planning and Conservation Act***—** H.R. 8157, reprinted in Cong. Rec. H 10687 (November 17, 1980).

Based on this broad authority, it is prudent for BPA to establish an adjustment charge to the base PF-02 rate that recovers the cost of serving unanticipated, incremental load during the rate period. Targeting the customer load that is causing the costs to be incurred is appropriate under the TAC, because it will apply to "those preference customers that place load that BPA did not anticipate serving to pay a price for firm power which reflects the cost to BPA of purchasing to serve this unanticipated load." Arrington *et al*., WP-02-E-BPA-24, at 3. As BPA testified, the TAC is based on the additional cost to BPA. Tr. 1075.

BPA does not agree with the PPC's contention that the TAC creates a tiered rate. The TAC will apply for the duration of the customer's contract or until 2006, whichever occurs first. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 37. As such, the TAC is an adjustment charge that applies no longer than the PF-02 rate period. The TAC will be calculated for an individual customer upon request by the customer for PF service after the Subscription window closes, and for certain other unanticipated incremental loads. Arrington *et al.*, WP-02-E-BPA-24, at 2. BPA may not be asked to serve any load under this charge. In fact, BPA does not expect to serve incremental loads and is forecasting that zero loads will be served under this charge. *Id.* at 6.

OURCA argues that the TAC is inconsistent with the Northwest Power Act because, OURCA claims, the Northwest Power Act requires BPA to reserve sufficient FBS resources to serve additional requests for service by public preference customers during the rate period. OURCA Brief, WP-02-B-OU-01, at 5; OURCA Ex. Brief, WP-02-R-OU-01, at 5. OURCA argues that, contrary to the statutory mandates of the Northwest Power Act, BPA's TAC proposal allows the nonpublic preference customers to reap benefits not accorded the public preference customers. *Id.* OURCA argues that the preference rights are mandatory, not discretionary, *Id.*, and cites section 5(a) and section 5(b)(2) of the Northwest Power Act and *City of Santa Clara, California v. Andrus*, 572 F.2d 660, 671 (9^{th} Cir. 1978) to support its position. ICNU argues that the TAC limits access to firm power by charging preference customers when they place unanticipated, incremental loads on BPA during the FY 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8.

As stated, BPA does not dispute that public body and cooperative utility customers are entitled to preference and priority under BPA statutes. OURCA's reliance on section 5(a) of the Northwest Power Act and the *City of Santa Clara* case are not dispositive on the issue of BPA's authority to sell power to non-preference customers, particularly once the net requirements of BPA's public body and cooperative utility customers have been met. The net requirements of BPA's preference customers will be met under contracts executed during the Subscription window. Burns and Elizalde, WP-02-E-BPA-37, at 4. BPA is not, however, obligated to hold a supply of available Federal power in reserve for the future needs of its preference customers. In fact, BPA is obligated to sell firm power to regional IOUs. Section 5(b)(1) obligates the Administrator to offer contracts to regional IOUs whenever requested. When BPA sells power to an IOU, section 5(b)(2) of the Northwest Power Act requires BPA to include in contracts with IOUs the right to reduce the Administrator's obligations under such contracts in accordance with section 5(a) of the Bonneville Project Act. Section 5(b)(2) states:

> Contracts with IOUs shall provide that the Administrator may reduce his obligations under such contracts in accordance with section 5(a) of the Bonneville Project Act of 1937 [16 U.S.C. §832d(a)].

16 U.S.C §839c(b)(2).

PPC argues that BPA's failure to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that may be assessed a TAC charge is discriminatory, arbitrary and capricious. PPC Ex. Brief, WP-02-R-PP-01, at 6. BPA's decision not to recall power sold to its nonpreference customers is not discriminatory, arbitrary, or capricious. To the contrary, BPA has reviewed it obligations under statute and determined that it is neither necessary, nor required at this time to recall power sold to BPA's nonpreference customers.

The notice language in section 5(a) of the Bonneville Project Act requires:

> [I]n the case of a contract with any purchaser engaged in the business of selling electric energy to the general public, the contract shall provide that the administrator may cancel such contract upon five years' notice in writing if in the judgment of the administrator any part of the electric energy purchased under such contract is likely to be needed to satisfy the requirements of said public bodies and cooperatives . . .

16 U.S.C. §832d(a).

This type of recall is to be used only when the Administrator has determined there would not be sufficient resources available on a planning basis to meet the Administrator's contractual load obligations to serve public agency customers. *Id.* Further, under section 5(d) of the Northwest Power Act, BPA is authorized to sell power under contracts with DSIs. Sales of power to nonpreference customers provide the preference customers a benefit through the additional revenues BPA receives through such sales. Such sales help keep BPA's rates low. If unanticipated, incremental load is placed on BPA by a preference customer during the rate period, the TAC will recover any costs BPA incurs to serve such customer. BPA's obligation to meet the net requirements of its preference customers is not impaired by the imposition of the TAC.

ICNU claims that preference customer access to firm power will be limited through application of the TAC during the 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8. ICNU cites several sections of statute: section 4(b) of the Bonneville Project Act, 16 U.S.C. §832c(b) ("Preference rights apply whenever there 'are conflicting and competing applications for an allocation of electric energy' between a preference customer and a private agency."); *Aluminum Co. of America v. Cent. Lincoln Peoples' Utility District,* 467 U.S. 380, 393 (1984); and sections 5(a) and 7 of the Northwest Power Act, 16.U.S.C. §839c(a) and §839e. *Id.* ICNU's argument that preference customer access for firm power will be limited lacks analysis and is not persuasive. To the contrary, BPA's direct testimony is that the net requirements of BPA's preference customers will be met under contracts executed during the Subscription window. Burns and Elizalde, WP-02-E-BPA-37, at 4. The TAC does not preclude preference customers from requesting BPA to serve their unanticipated, incremental load with firm power. When requested by such customers, BPA will provide service. Arrington *et al.*, WP-02-E-BPA-24, at 2. Moreover, it is not certain that TAC will "make the price of BPA power . . . so unattractive that no reasonable customer would purchase BPA power and be subject to these charges" as claimed by ICNU. ICNU Brief, WP-02-B-IN-02, at 9. To the contrary, BPA testified that as applied, the TAC may be zero if the additional cost to serve is zero. Tr. 1075.

PPC argues that policy decisions, such as BPA's policy on determining net requirements, will directly impact service to preference agency customers at BPA's PF rate, as opposed to service at a market-based PF TAC rate. PPC Brief, WP-02-B-PP-01, at 27. PPC contends that BPA testified that loads previously served by a customer's own firm resource would be subject to the TAC irrespective of whether or not load is expected and committed to Federal service within the Subscription window. *Id.* PPC contends this is discriminatory treatment unfounded in the law. *Id.*

Although PPC asserts that BPA's policy decision on net requirements and the proposed TAC result in discriminatory treatment that is unfounded in the law, PPC fails to show or proffer any evidence on the record in support of its claim. PPC's assertion is weak and unsupportable and, therefore, not persuasive. Despite PPC's claim to the contrary, BPA has testified that it will not apply the TAC to certain requirements loads that are forecast to materialize during the upcoming rate period, subject to the determination in the policy on determining net requirements. Arrington *et al.*, WP-02-E-BPA-49, at 8. A public customer will be allowed to include net requirements load in the initial amount under the Subscription contract that is being served with resources the customer demonstrates to BPA will terminate during the period from October 1, 2001, through September 30, 2006. *Id.* The customer's load that was served by the terminated resource(s) will not be subject to the TAC if such demonstration can be made at the time the contract is executed, consistent with the policy on determining net requirements. *Id.* Load that does not meet this requirement will be subject to the TAC. *Id.*

Decision

The TAC is a cost-based adjustment to the applicable rate. The TAC is not a tiered rate and does not result in discriminatory rates.

Issue 2

Whether BPA's Loads and Resources Study, WP-02-E-BPA-01, presents a reasonable forecast of BPA's loads and resources to support BPA's determination to implement the TAC.

Parties' Positions

In its initial brief, PPC makes several new arguments regarding BPA's Loads and Resources Study, WP-02-E-BPA-01, which is used in support of BPA's determination to impose a TAC. PPC Brief, WP-02-B-PP-01, at 28-29. PPC argues that: BPA's load/resource balance analysis does not accurately predict if the agency will in fact be surplus or deficit for the FY 2002-2006 rate period; BPA's pending policy on determining net requirements will have an unknown impact on BPA's load/resource balance analysis; the outcome of the IOU settlement as a section 5(b) requirements sale or a sale under section 5(c) of the Northwest Power Act will have an impact on BPA's load/resource balance analysis; and there is an internal inconsistency showing the unreliability of the loads and resources estimates that support BPA's proposed TAC. *Id*.

BPA's Position

The only evidence on the record regarding the methodology used in developing the public agency load forecast is contained in BPA's direct case. Loads and Resources Study, WP-02-E-BPA-01, at 3-4; Loads and Resources Study Documentation, WP-02-E-BPA-01A, at 8-11. No party filed any direct or rebuttal testimony demonstrating that a customer-specific methodology was preferable or that an aggregate approach was unacceptable. No party cross-examined BPA witnesses on loads and resources on this topic either, leaving BPA's Loads and Resource Study, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A, unrebutted. Nor did any party present any direct or rebuttal testimony demonstrating that BPA's net requirements policy, including the outcome of the IOU exchange settlement, would have any impact on BPA's loads and resources forecast.

Evaluation of Positions

PPC argues that BPA's load/resource balance analysis does not accurately predict if the agency will in fact be surplus or deficit for the FY 2002-2006 rate period, because it is not performed on a customer-specific basis. PPC Brief, WP-02-B-PP-01, at 28. PPC also refers to "questionable assumptions" about continuing "diversification" levels and public agency annexations. *Id*. This statement suggests that the PPC doubts the reasonableness of the forecasts of these items.

The PPC has not offered any evidentiary support for the conclusion that the aggregate method used to forecast public agency loads presented in BPA's direct case is unreasonable. Nor has the PPC offered any evidentiary support for the conclusion that the assumptions about the level of diversification and the anticipated annexation of new public loads in BPA's direct case are unreasonable. Rather than pointing to some evidence in the record, the PPC relies on conclusory statements in its brief that the method and assumptions employed in BPA's direct case will result in inaccurate predictions. PPC Brief, WP-02-B-PP-01, at 28. Without some factual support in the record to support rejecting the methodology and assumptions contained in BPA's direct case, it would be unreasonable to do so.

PPC had ample opportunity to offer alternative methods and assumptions for these items in its direct case or to question the reasonableness of these items during cross-examination. Neither they, nor any other party, did so. Therefore, it is inappropriate to question the validity of these items at this juncture. PPC argues that because BPA's net requirements policy has not yet been published, its impact on BPA's load/resource balance analysis cannot be known at this time. PPC Brief, WP-02-B-PP-01, at 28. The PPC has not offered any evidentiary support for the inference it makes that BPA's net requirements policy will have an impact on BPA's forecast of public agency loads. BPA testified that it believes there will not be a substantial change to its load forecast resulting from BPA's final policy on net requirements. Tr. 1085. Without some factual support in the record, it would be unreasonable to reject the forecast contained in BPA's direct case.

PPC argues that BPA's load/resource balance is further weakened by not accounting for the IOU settlement as a Northwest Power Act section 5(b) requirements sale. PPC Brief, WP-02-B-PP-01, at 28. PPC contends that if the outcome of the settlement is based on a section 5(c) sale under the Northwest Power Act, it will reduce the agency's need for system augmentation. *Id*. at 29.

The PPC has not offered any evidentiary support for its claim that the IOU settlement will weaken BPA's Loads and Resources Study, WP-02-E-BPA-01. Rather than pointing to some evidence in the record, the PPC relies on a conclusory statement in its brief that the outcome of the IOU settlement will weaken BPA's Loads and Resources Study, WP-02-E-BPA-01. *Id*. Without some factual support in the record to support rejecting the assumptions contained in BPA's direct case, it would be unreasonable to do so. In addition, sales made under sections 5(c) and 5(b) are in fact direct sales. Regardless of whether BPA's IOU settlement sales are made under section 5(b) of the Northwest Power Act using the RL rate or section 5(c) using the PF Exchange Subscription rate, there will be an actual power sale to the purchasing utility. That is what the Subscription Strategy settlement intends for IOU settlement sales. Because the sale is an actual delivery of power, the forecast is correct for sales under either section 5(b) or 5(c).

PPC argues that from BPA's load/resource analysis it can be concluded that the region is 189 aMW deficit at the end of Operating Year (OY) 2006. PPC Brief, WP-02-B-PP-01, at 29. PPC states that while this conclusion seems to support BPA's testimony that it will have to supplement the FBS to serve some post-2001 public agency load, elsewhere BPA testifies that there is no constraint on the supply of Federal power available for preference customers for the FY 2002-2006 rate period. *Id*. PPC then asks the question: "In a period of deficit with no planned recall, how is it that 'no constraint' exists when preference customers face the market price, rather than PF?" *Id*.

Again, PPC makes conclusory statements without any evidence to support its conclusions. PPC has misinterpreted the Loads and Resources Study, WP-02-E-BPA-01, and wrongly concludes that BPA will be deficit. After properly accounting for sales forecasts and BPA's contractual obligations in this rate case, and Federal system resource estimates including capacity for energy exchanges, contractual resources, and other BPA hydro-related contracts, BPA is in load/resource balance on a fiscal year basis. Arrington *et al*., WP-02-E-BPA-24, at 6; Loads and Resources Study, WP-02-E-BPA-01, at 2. *See* table, *Id*. at 18. The TAC will provide BPA the flexibility to meet increases in BPA's regional firm load obligations during the rate period, Arrington *et al*., WP-02-E-BPA-49, at 2; and to recover the costs of incremental, unanticipated load that is not forecast to be served during the FY 2002-2006 rate period, Arrington *et al*., WP-02-E-BPA-24, at 2. BPA does not expect to serve incremental loads and is forecasting that zero loads will be served under this schedule. *Id*. at 6.

Decision

BPA's Loads and Resources Study, WP-02-E-BPA-01, presents a reasonable forecast of BPA's loads and resources and supports BPA's determination to implement the TAC.

Issue 3

Whether BPA's decision regarding exercising its right to recall power to serve requirements load violates the Northwest Power Act.

Parties' Positions

NRU argues that as a matter of law, if firm power is available, or if BPA could make it available by exercising rights to recall power, public agency customers are entitled to receive it based on their statutory rights as preference customers, and they should pay only a cost-based PF-02 rate. NRU Brief, WP-02-B-NI-02, at 28. PPC notes that BPA does not plan to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that will otherwise be assessed a TAC. PPC Brief, WP-02-B-PP-01, at 25.

BPA's Position

While BPA does have a statutory obligation to include in contracts a right to recall surplus firm power sold or exchanged under extraregional contract, as well as surplus firm power sold as replacement power in the region, BPA has determined that it is not necessary at this time to exercise that right. Arrington *et al*., WP-02-E-BPA-49, at 7. On a planning basis, BPA has determined that it can meet all expected PNW customer requirements without having to exercise its rights to recall surplus firm power by purchasing in the market or relying on seasonal surplus firm power. *Id*.

Evaluation of Positions

NRU argues that BPA is obligated by law to use its statutory and contractual recall rights to make FBS power available to serve public agency customers. NRU Brief, WP-02-B-NI-02, at 28. PPC notes that BPA does not plan to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that will otherwise be assessed a TAC. PPC Brief, WP-02-B-PP-01, at 25. PPC states that BPA will not recall despite a "number of contracts identified in this rate case that could be recalled for the purpose of serving regional load totaling approximately 200 aMW." *Id*.

While BPA does have a statutory obligation to include a right to recall surplus firm power sold or exchanged under extraregional contract, as well as surplus firm power sold as replacement power in the region, BPA has determined that it is not necessary at this time to exercise that right. Arrington *et al*., WP-02-E-BPA-49, at 7. BPA's obligation regarding recall of surplus firm power under extraregional power sales contracts arises under section 3(a) of the Pacific Northwest Consumer Power Preference Act of 1964, 16 U.S.C. §837b(a). Section 3(a) provides in part:

> Any contract for the sale or exchange of surplus firm energy for use outside the PNW, or as replacement, directly or indirectly, within the PNW for hydroelectric energy delivered for use outside the region by a non-Federal utility, shall provide that the Secretary, after giving the purchase notice not in excess of 60 days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirements of any PNW customer.

16 U.S.C. §837b(a).

Consistent with the law, BPA does not foresee that its ability to serve returning uncommitted load of customers subject to the TAC is impaired because of sales of surplus firm power under extraregional contracts. The 1974 Transmission Act and the 1980 Northwest Power Act grant BPA ample authority to acquire power to meet the Administrator's obligations under contract to serve load. As long as resources can be acquired and are available on a planning basis to meet BPA's load requirements, BPA can reasonably foresee that its ability to serve unanticipated load will continue unimpaired. Further, the exercise of the Administrator's right to recall surplus firm power under extraregional contracts is compelled to meet the Administrator's supply obligation only. Recall is not required to provide any customers a price. On a planning basis, BPA has determined that it can meet all expected PNW customer requirements without having to exercise its rights to recall surplus firm power by purchasing in the market or relying on seasonal surplus firm power. Arrington *et al*., WP-02-E-BPA-49, at 7.

Decision

BPA's decision not to recall power to serve requirements load is consistent with the directives of the Northwest Power Act.

10.16 Cost-Based Indexed Rate Options

10.16.1 Cost-Based Indexed PF Rate

The cost-based indexed PF rate is a rate conversion from the applicable PF rate to a market-indexed or floating price. Miller *et al.*, WP-02-E-BPA-21, at 16. The rate indexed to market would not be fixed but would rise and fall with market prices, although it is adjusted for BPA's risk and designed to achieve revenues equivalent to the applicable PF rate. *Id.* at 17. There are several reasons why BPA is offering the cost-based indexed PF rate. *Id.* First, it extends BPA's ability to offer its customers pricing flexibility related to the market. *Id.* Second, the cost-based indexed PF rate allows BPA to better tailor the rate to reflect the risks associated with the market. *Id.* Third, it is an alternative to take-or-pay contract provisions, since the customer assumes the market risks. *Id.* Finally, it provides a product alternative to BPA's customer's end-use consumers, particularly industrial and large commercial loads, seeking market-based electric rates. *Id.* During contract negotiations the customer may request the cost-based indexed PF rate; it is, however, in BPA's discretion to offer this product. *Id.* If BPA decides to offer the product, BPA and the customer will negotiate and agree on either a commercially viable cash index or a futures index with which to reference the rate price. *Id.* For example, the COB DJ cash indexes or the New York Mercantile Exchange (NYMEX) futures contract at COB, or some other commercially recognized combination may be used to arrive at an agreed-upon index. *Id.* If a cash index is chosen, BPA will use that index to establish the monthly settlement price for the customer's power bill. *Id.* If a futures index is chosen, BPA will set the index price based on a monthly settlement formula taken from that index. *Id.* Whichever kind of index is used, the monthly price for power will be set based upon a negotiated formula for calculating price. *Id.* Such a formula may be either a single expiration price, a monthly average, or some other average of the month's prices. *Id.*

Because BPA will base the index pricing on a current market forecast of the market index referenced, BPA will adjust the current market price over the contract period against BPA's cost.

Id. at 18. This may result in either a discount or a premium that will be applied to the calculation of each month's bill. *Id.* In addition, BPA will add a hedging or insurance cost. *Id.* Such insurance, in the event market prices are below BPA costs, may consist only of the premium or difference between cost and market. *Id.* If, on the other hand, market prices are above BPA costs, such insurance may reduce the amount of any monthly discount applied to a customer's power bill. *Id.* The expected NPV revenue of the forecast index prices will be adjusted by a HLH and LLH Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rate. *Id.* The MIMA is the difference between cost and market for power in both HLH and LLH periods indexed and adjusted monthly. *Id.* In the case of a discount to market, MIMA includes the added cost of price insurance. *Id.* The MIMA is calculated at the time of contract origination and remains effective throughout the life of the contract. *Id.* The MIMA essentially allows BPA to mark an index contract up or down from market prices, and back to BPA's cost, based on the current forward market transaction price. *Id.* By doing this the forecasted revenues will be equal to revenues under the posted PF rates. *Id.*

Customers can elect to apply this rate up to five years. *Id.* Customers who elect a contract length of less than five years and wish to renew may be subject to rates established under a new rate case and the recalculation of the MIMA. *Id.*

Unlike prices under fixed rate schedules, the price for power sold under contracts subject to the cost-based indexed PF rate will change with the market. *Id.* at 19. Because of market volatility, market prices range widely. *Id.* Therefore, the risk inherent in the cost-based PF rate could be great. *Id.* For BPA, the risk is that market prices will fall, resulting in a below-cost price. *Id.* For customers, the risk is that prices will rise, resulting in a higher price than they would have paid at a fixed PF rate. *Id.*

To protect itself from underrecovering system costs, BPA will use risk management tools, such as put options, to protect such contracts. *Id.* The cost of such insurance will be a reduction to any discount when market prices are above the PF rate at the time a contract is signed. *Id.* If market prices are below the PF rate, then BPA will add an appropriate premium to the monthly calculation of the settlement price (*see* above discussion of MIMA). *Id.* The settlement price is based on a mutually agreed-to formula that calculates an average based on some certain number of days within the delivery month; *e.g.*, average of last 15 days in the delivery month. BPA may also use index-type transactions of this kind to protect itself against higher-than-PF market purchases. *Id.*

PPC opposed BPA's proposal to price requirements service at the Cost-Based Indexed PF rate, arguing that it is a fiction the rate is cost-based and that by offering this rate design, additional risks and costs will be borne by BPA's other customers. Opatrny *et al*., WP-02-E-PP-02, at 25. In BPA's rebuttal testimony, BPA stated that the Cost-Based Indexed PF rate is being proposed in this rate case to provide customers with flexibility to choose a floating price under BPA's fixed cost-based rate. Miller *et al*., WP-02-E-BPA-46, at 25. The cost-based indexed PF rate is indexed to market and hence, will rise and fall with market prices. *Id.* The Cost-Based Indexed PF rate will be adjusted for BPA's risk and is designed to achieve revenues equivalent to the applicable PF rate. *Id.* The Cost-Based Index is priced at the time of contract origination and will account for any difference between BPA and market prices when market prices are above the fixed PF rate. BPA is confident that such sales, as they are currently and prospectively structured, are cost-based and will not result in the additional risks alluded to in PPC's testimony. *Id.* Neither PPC, nor any other party raised the issue of the cost-based indexed PF rate on brief. *See Procedures*, 51 Fed. Reg. 7611 (1986).

10.16.2 Cost-Based Indexed IP Rate

Issue 1

Whether BPA should offer the DSI customers a Cost-Based Indexed IP rate option.

Parties' Position

WPAG argues that BPA should not offer the Cost-Based Indexed IP rate option (indexed rate) to the DSIs. WPAG Brief, WP-02-B-WA-01, at 12. WPAG argues that prior indexed, or variable, IP rates were offered when there were benefits to BPA in offering such a rate, including the need to retain DSI load, but that those benefits are not present today. *Id*. WPAG argues that BPA has presented no evidence to support the contention that some DSI aluminum smelters may not survive absent an indexed rate. And even if such evidence were in the record, offering a discount rate to a subset of BPA's customers on the premise that their financial survival is in question may be inconsistent with BPA's obligation to set rates in a sound and business-like manner. *Id*. WPAG concludes that the indexed rate is designed to attract substantial amounts of load of customers that may not survive through the rate period, and that while BPA may have the discretion to offer an indexed rate, there is no compelling reason to do so. *Id*. at 13.

In a related argument, SUB argues that BPA's proposal to enter into 100 percent firm power sale agreements with the DSIs in the post-2001 period violates the preference and priority rights of public customers. SUB Brief, WP-02-B-SP-01, at 2-3. SUB argues such sales also are inconsistent with the precedent set by contracts entered into by BPA with the DSIs prior to the Northwest Power Act (16 U.S.C. §839-839h), which provided that a portion of such sales were subject to interruption, thus making that portion subject to the preference provisions of the Bonneville Project Act (16 U.S.C. §832-832m) and enabling preference utilities to interrupt it whenever they wanted nonfirm energy. *Id*. at 3. SUB appears to conclude that because the pre-Northwest Power Act contracts with the DSIs were discretionary and contained interruption rights, that discretionary post-2001 DSI contracts must also contain interruption rights to comply with the preference and priority provisions of the statutes. *Id*. Alternatively, SUB proposes that these defects may be cured by adopting SUB's proposals for correcting BPA's 7(c)(2) rate proposal. *Id*. at 4.

No other party opposes BPA's proposal to offer an indexed rate to the DSIs. However, other parties do argue for different treatments of the proposed parameters of the indexed rate, the level of risk associated with the rate, and how that risk should be mitigated by BPA. These issues are addressed at Issue 2 in this section.

BPA's Position

BPA argued that a conservatively structured indexed rate that does not place unreasonable levels of additional cost risk on other customers will provide an important short-term survival tool for DSI aluminum smelters. Miller *et al*., WP-02-E-BPA-21, at 2. Some DSIs represented to BPA that the availability of an indexed rate in the event of low aluminum prices will likely be important to their decision to maintain the operation of some of the aluminum smelters. *Id*. The 10 aluminum smelters and 1 aluminum rolling mill in the region served directly by BPA directly employ approximately 10,000 workers at full operations. *Id*. at 3.

BPA conducted a general analysis of the aluminum industry in the region to determine the effect power prices would have on the continuation of smelter operations under different aluminum prices. Berwager *et al*., WP-02-E-BPA-09, at 11. BPA concluded from this analysis that under certain reasonably possible combinations of low aluminum and high power price assumptions, the proposed indexed rate would provide an important tool to improve the likelihood of smelter survival. *Id*. at 11-14. The indexed rate was designed around rate and aluminum price parameters so that, on a projected basis, BPA will recover revenues over the rate period equivalent to revenues it would recover from a DSI through the proposed fixed IPTAC rates. Miller *et al*., WP-02-E-BPA-21, at 3.

Evaluation of Positions

WPAG correctly points out that BPA does not benefit from an indexed rate for the DSIs in the upcoming rate period as it did under prior DSI indexed or variable rates. BPA's benefit from past variable rates was sales for BPA during periods of large power surpluses and low energy market prices in limited markets. Miller *et al*., WP-02-E-BPA-46, at 22. The general belief today is that energy market prices during the 2002-2006 period will be fairly robust, so those particular benefits will not likely occur. *Id*. However, BPA proposed the indexed rate primarily to help mitigate the possibility, during temporary periods of low aluminum prices, of aluminum smelter shutdown and the consequent loss of smelter jobs. *Id*. WPAG's assertion is incorrect that "[n]ot a shred of evidence," WPAG Brief, WP-02-B-WA-01, at 12, has been introduced into the record to support the contention that such a rate may enhance the prospect of smelter survivability.

BPA conducted a general survivability analysis using scenarios with power market rates during FY 2002-2006 that averaged 26, 28, and 30 mills/kWh and combined them with aluminum price scenarios of 60, 65, 70, 75, and 80 cents per pound. Berwager *et al*., WP-02-E-BPA-09, at 11. Using four major elements of production cost data for each smelter (power, alumina, labor, and other) BPA analyzed likely smelter operations under these aluminum and power market conditions, assuming BPA would supply approximately half the smelter's power at 1 mill increments from 18 mills/kWh to 28 mills/kWh, with the other half supplied by the market at prices ranging from 26 to 30 mills/kWh. *Id*. Based on this analysis, BPA concluded that the likelihood that smelter operations would continue was most sensitive to energy prices when aluminum prices were in the 65 to 70 cents per pound range under all the power market price scenarios (26, 28, and 30 mills/kWh). *Id*. at 12. To take just one scenario examined, BPA's analysis suggests that if aluminum prices are at 68 cents and the smelters had to purchase all their power in the market at 28 mills/kWh (approximately BPA's estimate of the average long-term purchase price for five-year flat-block energy, *see* Oliver *et al*., WP-02-E-BPA-20, at 7); then 68 percent of smelter loads are at risk of not operating. *Id*. at 13. At this combination of aluminum and energy market prices, however, the amount of smelter load at risk drops by approximately one-half to two-thirds if BPA supplies half the smelter's power under the applicable indexed rate. *Id*.

WPAG suggests that, even if survivability of the DSI smelters were demonstrated, offering a discount rate to a subset of BPA's customers on the premise that their financial survival is in question may be inconsistent with BPA's obligation to set rates in a sound and business-like manner. WPAG Brief, WP-02-B-WA-01, at 12. WPAG states that the proposed IP indexed rate is a "rate concession" designed to attract a sizable amount of load with customers that BPA believes may not survive the rate period and that BPA believes are likely not to be able to pay their power bills in the future. *Id*. at 13.

WPAG's concerns are not supported by the record. The indexed rate was not designed to attract DSI load to that rate, and BPA would prefer that the DSIs make their purchases at the applicable fixed IPTAC rate. Miller *et al*., WP-02-E-BPA-46, at 11. Nevertheless, the effect of expected higher market prices for electricity is to make it more difficult for DSI operations to continue in the Northwest if the DSIs are required to purchase all or most of their power at those higher market prices during a period of low aluminum prices. Berwager *et al*., WP-02-E-BPA-09, at 6. The jobs in jeopardy are important to the region and, especially, to the communities in which these plants are located. *Id*. Service to these customers is consistent with BPA's mission to spread the benefits of Federal power widely throughout the region. *Id*.; *see also* Bonneville Project Act, 16 U.S.C. §832, §832e.

BPA recognizes there is a moderate risk that the power market could be below the proposed indexed rate lower rate limit of 19 mills/kWh at the time the DSI curtails load or shuts down its plant. Miller *et al*., WP-02-E-BPA-46, at 10, 13. However, any financial risk BPA faces from the inability of a DSI to survive through the next rate period is mitigated by the fact that any power returned to BPA for remarketing will more likely be sold into the market at an average price at or above the low indexed rate then being paid by such DSI, since smelter survivability is most imperiled at low aluminum prices and, therefore, a low indexed rate.

SUB argues that BPA's proposal to enter into 100 percent firm power sale agreements with the DSIs in the post-2001 period violates the preference and priority rights of public customers. SUB Brief, WP-02-B-SP-01, at 2-3. SUB cites *Aluminum Co. of America v. Central Lincoln Utility District*, 467 U.S. 380 (1984), (*Alcoa*) for the proposition that the preference and priority rights of BPA's preference customers are preserved with respect to administrative allocations of power to the DSIs after expiration of the DSIs' initial 20-year contracts. SUB Brief, WP-02-B-SP-01, at 3. BPA does not disagree that the preference and priority provisions apply to such discretionary sales to non-preference customers such as the DSIs, but BPA does not agree with SUB's conclusion that those rights are violated by BPA's proposal to enter into new five-year firm, non-interruptible contracts with the DSIs. SUB appears to argue that the discretionary or administrative post-2001 allocations of power to the DSIs require that those contracts mirror the interruptibility provisions of the discretionary pre-Northwest Power Act (the 1975) contracts in order to comply with the preference and priority provisions.

Under the 1975 contracts, the top quartile of power sold to the DSIs was subject to interruption "at any time," thereby making the top quartile of DSI power subject to the preference provisions of the Bonneville Project Act, 16 U.S.C. §832, §832d(a)), and enabling preference customers to interrupt it whenever they wanted nonfirm energy. *Alcoa*, 467 U.S. 380, 387 (1984). When BPA offered the DSIs their 1981 contracts, BPA interpreted section 5(d)(1)(b) of the Northwest Power Act to require only that the new DSI contracts were to "provide a portion of the Administrator's reserves for firm power loads within the region," 16 U.S.C. §839c(d)(1)(B)); so the new contracts allowed interruption only to protect BPA's firm loads and not to make sales of nonfirm energy. *Alcoa*, at 387. BPA's public preference customers challenged BPA's decision, but that decision was eventually upheld in *Alcoa*.

SUB's reliance on *Alcoa* for the proposition that the post-2001 contracts with the DSIs must be interruptible on the same terms as the 1975 contracts in order to comport with public preference is misplaced for several reasons. First, as pointed out by the court in *Alcoa*, under the 1975 contracts the difference between the top quartile and the other quartiles was the provision in those contracts that made the top quartile subject to interruption "at any time." That term allowed the Administrator to treat the top quartile as if it were uncommitted, and subjected it to preference. The other three quartiles were not subject to preference simply because the terms of the contracts did not so provide. The court concluded from this that "the distinction among the different quartiles under the 1975 contracts was a product of the terms of the contracts, not a requirement of the Project Act's preference provisions." *Alcoa*, at 394. Thus, *Alcoa* does not support SUB's contention that, in the case of a discretionary allocation of power to the DSIs, the preference laws required that only less than all-firm contracts may be offered to the DSIs.

Second, BPA does not dispute that the preference rules apply to post-2001 sales to the DSIs. *See Alcoa*, at 395, n. 10 (preference rules will apply to any subsequent contracts made with the DSIs). However, as discussed above, BPA is not obligated by the preference laws to offer less than all-firm contracts to the DSIs in order to provide preference customers with a source of nonfirm energy, and SUB has provided no evidence that there is any competing demand from any public preference customer to the proposed power allocation to the DSIs in order to meet its firm net requirements load, or that BPA is not meeting all such requests. *See* Loads and Resources Study Documentation, WP-02-E-BPA-01A. Finally, post-2001 section 5(d) sales to the DSIs, while discretionary, are still made pursuant to section 5(d)(1)(A) of the Northwest Power Act, which limits the reserves provided by the DSIs to those needed to meet the Administrator's firm power loads. 16 U.S.C. §839c(d)(1)(A). These reserves are not free, and the DSIs must be compensated for the right to interrupt power deliveries to provide these power reserves. However, as a result of deregulation and other factors, it may be neither necessary nor cost-effective for the PBL to purchase any reserves from the DSIs during the next rate period. *See* McRae *et al*., WP-02-E-BPA-29. However, the point is that section 5(d)(1)(A) requires that the DSIs' contracts be available for interruption to provide reserve power for only the firm, and not the nonfirm, loads of the Administrator.

Decision

BPA will offer an indexed rate option to its DSI aluminum smelter customers to further BPA's policy goal of enhancing DSI smelter survivability and associated smelter jobs during periods of low aluminum prices. In addition, BPA's proposal to make 100 percent of the firm power sales to the DSIs under either the applicable indexed or fixed IPTAC rates is consistent with the preference and priority provisions in BPA governing statutes.

Issue 2

Whether BPA's proposal correctly accounts for the risks associated with the indexed IP rate, including whether BPA should adopt a minimum aluminum price forecast of 74 cents.

Parties' Positions

The DSIs contend that BPA's indexed rate proposal does not adequately reflect the strong consensus of predictive aluminum price forecasts that aluminum prices will average 76 cents/lb. or higher during the 2002-2006 rate period, and is therefore not consistent with the Compromise Approach agreement. DSI Brief, WP-02-B-DS-01, 40-46. The DSIs argue that the indexed rate parameters negotiated between BPA and the DSIs, taken together with the "commonly accepted" meaning of the term "forecast," make it unreasonable to think that the DSIs ever agreed to BPA's proposal for a fully hedged indexed rate as part of the Compromise Approach agreement. *Id*. at 43. The DSIs propose that in setting the midpoint of the indexed rate, BPA should adopt an aluminum price forecast that gives at least equal weight to the actual forecasts in the record as it gives to forward price curves, and that the 74 cents/lb. proposal made by the DSIs' expert is the lowest reasonable midpoint. *Id*. at 43-44. They claim that an indexed rate with a midpoint of 74 cents/lb. will provide BPA median revenues that correspond to a fixed price of $23.50/MWh. *Id*. at 44. The DSIs argue that BPA's rationale in the Draft ROD, that an aluminum price forecast above 74 cents/lb. is not needed to address DSI survivability concerns, is not relevant to the Compromise Approach. DSI Ex. Brief, WP-02-R-DS-01, at 6. They contend that the indexed rate parameters must be based on an aluminum price forecast developed in the rate case, not on an assessment of smelter operations or smelter survivability developed in the rate case. *Id*. at 7. The DSIs also take exception to BPA's position that the DSI aluminum expert does not qualify as an independent consultant under the Compromise Approach agreement. *Id*. at 8.

The DSIs argue that the aluminum market "backwardization" extant at the time the Draft ROD was published will result in BPA fixing the midpoint of the indexed rate at a level much below expected real aluminum prices, with the consequence that the DSIs will not realize any advantage from the indexed rate, and making the financial hedge particularly costly. *Id*. at 44-45. The DSIs state that BPA does not intend to financially hedge all its other risks, and that it is particularly unfair to single out the DSIs to pay for what amounts to a very high cost hedge. *Id*. at 46. They urge BPA, if it adopts the proposal to fully hedge the indexed rate risk, to remain flexible as to both the spread and the timing of a DSI's commitment to an indexed rate, and that BPA should not place an absolute upper limit of 74 cents/lb. on the aluminum price midpoint. *Id*.

The IOUs argue that BPA's proposed design for the indexed IP rate places on other customer classes an unreasonable risk of cost shifts. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63-64. The IOUs argue that BPA has not accounted for this risk, that BPA is proposing to absorb the risk associated with the varying price of aluminum, and that ultimately BPA may be forced to try to turn to its transmission customers to cover the costs of that risk. *Id*. at 64.

PPC argues that the proposed indexed IP rate, unless fully hedged by BPA and priced to include the full cost of the hedge, represents a significant cost to BPA's public utility customers. PPC Brief, WP-02-B-PP-01, at 60-61. PPC asserts that an unhedged indexed IP rate would be costly to other BPA customers, because their power costs would be less predictable, given the increased risk that BPA may need to resort to the proposed CRAC to cover any revenue underrecoveries associated with low aluminum prices, and because under the proposed CRAC such a rate increase is not offset by an equivalent rate decrease in the event of a revenue windfall associated with high aluminum prices. *Id*.

PPC proposes that all the indexed rate parameters should be adjusted at the time the hedge is made, to be consistent with the fully hedged position, and that the hedged position must reflect the "price of the options" embedded in the rate structure. *Id*. PPC asserts there is no justification for BPA's offer of a 2 cent "subsidy" and that this is inconsistent with the principle of offering a fully hedged rate with revenues equivalent to the applicable fixed IPTAC rate. *Id*. Finally, PPC maintains that basing the midpoint of the indexed rate on predictive price forecasts would expose BPA customers to significant risk and would fail to take into account the cost of the hedge, which should be paid by the DSIs. *Id*.

BPA's Position

BPA agreed in the Compromise Approach agreement to propose an indexed IP rate tied to the price of aluminum, in response to the assertion by some DSIs that the availability of such a rate will likely be important to their decisions to maintain the operation of some of the smelters in the event aluminum prices do not recover during the next rate period. Berwager *et al*., WP-02-E-BPA-09, 2-4; Miller *et al*., WP-02-E-BPA-21, at 2. However, BPA has consistently made it clear that a fundamental benchmark for any indexed rate was that it neither result in increases in BPA's proposed rates for other customers, nor place unreasonable levels of additional cost risk on other customers. *See e.g.*, Miller *et al*., WP-02-E-BPA-21, at 2-3; Miller *et al*., WP-02-E-BPA-46, at 3-4, 11, 22. Because the indexed rate moves up or down with the price of aluminum, such a rate clearly presents some revenue uncertainties for BPA due to potentially unstable or chronically depressed aluminum prices. *Id*. at 7. Because BPA has not accounted for this revenue risk in its planned net revenues for risk, it is necessary that if indexed rate contracts are signed BPA have the ability to simultaneously protect expected revenues by hedging against this risk with financial instruments. *Id*. Therefore, BPA proposed indexed rate parameters, including the lower and upper rate limits, the pivot points, and the slope, in an attempt to strike a balance between enhancing DSI smelter survivability during periods of low aluminum prices and creating a high probability of collecting revenues equivalent to the IPTAC rates of 23.5 mills/kWh and 25.0 mills/kWh over the five-year rate period, thereby mitigating risks to other customers. Miller *et al*., WP-02-E-BPA-21, at 9-11.

In addition, BPA proposed that the aluminum price forecast midpoint, which is the point at which the aluminum price and indexed power rate intersect at BPA's expected cost of service (23.5 or 25.0 mills/kWh), be set approximately 2 cents/lb. higher than the forward price for aluminum at the time indexed rate contracts are signed. Miller *et al*., WP-02-E-BPA-46, at 2-5. Again, this aspect of the proposal seeks to balance the DSIs' survivability concerns against the goal of not shifting unreasonable levels of cost risk to other customers. By proposing an aluminum forecast midpoint that is approximately 2 cents/lb. higher than transactable forward prices, BPA is assuming some aluminum price risk for the DSIs. *Id*. at 4. On the other hand, setting the midpoint no more than 2 cents/lb. above transactable forward prices will allow BPA to hedge this risk as soon as practicable to protect BPA's other customers from additional costs. *Id*.

The Compromise Approach agreement states that the price forecast used to establish the indexed rate will include both forward prices and aluminum price forecasts (Berwager *et al*., WP-02-E-BPA-09, Attachment 1), and BPA's proposal balances those two elements appropriately and fairly. Miller *et al*., WP-02-E-BPA-46, at 3. The more credence BPA places on the accuracy of long-term predictive price forecasts, the more risk BPA must assume. *Id*. The DSIs' proposal that BPA give more weight to the predictive forecasts would require BPA to accept aluminum price risk at levels higher than are required to meet BPA's fundamental goal for service to the DSIs, which is to enhance the prospects of smelter survivability during periods of low aluminum prices while not imposing additional costs on BPA's other customers. *Id*. BPA's proposal balances these goals by proposing to establish the aluminum forecast midpoint approximately 2 cents/lb. above the forward price at the time an indexed rate contract is signed, but not below 66 cents/lb. or above 74 cents/lb., and is fully consistent with the Compromise Approach agreement. *Id*. at 6.

<u>Evaluation of Positions</u>

The DSIs state that the record indicates a strong consensus among the predictive aluminum price forecasts that aluminum prices will average 76 cents/lb. or higher during the FY 2002-2006 rate period. DSI Brief, WP-02-B-DS-01, at 42. While acknowledging that the Compromise Approach does include forward price curves as part of the basis for the aluminum price forecast, the DSIs argue the large spread between forward prices and even the lowest of the range of predictive price forecasts in the record show that BPA is "not truly" giving any weight to the forecasts. *Id*. at 43. The DSIs conclude from this that BPA's proposal to establish the aluminum price forecast (and thus the indexed rate midpoint) approximately 2 cents/lb. above forward prices, but not lower than 66 cents/lb. or higher than 74 cents/lb., is inconsistent with the Compromise Approach agreement and "the reasonable expectations that the DSIs gained from negotiating the Compromise Approach with BPA." *Id*. The DSIs propose that the 74 cents/lb. forecast presented by the DSI expert is the lowest reasonable midpoint aluminum price for the indexed rate. *Id*. at 44. The DSIs' argument that BPA's proposal on this issue is inconsistent with the Compromise Approach is wrong because: (1) it fails to acknowledge the context in which BPA agreed to propose an indexed rate for the DSIs; and (2) it incorrectly concludes that BPA is not giving sufficient weight to predictive aluminum price forecasts in its proposal for establishing the indexed rate midpoint.

The indexed rate piece of the Compromise Approach agreement was based on the principle that BPA was willing to take a moderate amount of risk in order to fashion a DSI service package that would help enhance the prospects of DSI smelter survivability and preserve smelter jobs. Miller *et al*., WP-02-E-BPA-46, at 2. The DSIs' assertion that BPA's proposal violates the Compromise Approach because it would not allow the establishment of an aluminum forecast above 74 cents/lb. fails to acknowledge these fundamental principles around which the Compromise Approach agreement was negotiated. The record contains no evidence for the proposition that DSI smelter survivability is threatened if aluminum prices rise above 74 cents/lb., or conversely that an indexed rate midpoint above 74 cents/lb. would enhance survivability. In fact, BPA's analysis showed that of all the aluminum price scenarios examined, the likelihood that smelter operations would continue was most sensitive to energy prices when aluminum prices were in the 65 to 70 cent/lb. range under power market price scenarios of 26, 28, and 30 mills/kWh. Berwager *et al*., WP-02-E-BPA-09, at 12.

Nevertheless, the DSIs continue to argue BPA's conclusion that an aluminum price forecast above 74 cents/lb. is not needed to address DSI survivability concerns is not relevant to the Compromise Approach. DSI Ex. Brief, WP-02-R-DS-01, at 6. They contend that the indexed rate parameters must be based on an aluminum price forecast developed in the rate case, not on an assessment of smelter operations or smelter survivability developed in the rate case. *Id*. at 7. However, as already noted, the purpose for the indexed rate, in fact the primary purpose behind BPA's entire proposal for service to the DSIs, is to enhance the prospect for the survival of the DSI aluminum smelters and associated jobs during periods of low aluminum and high power prices, through the next rate period. *See, generally,* Berwager *et al*., WP-02-E-BPA-09; Berwager *et al*., WP-02-E-BPA-38; Miller *et al*., WP-02-E-BPA-21; Miller *et al*., WP-02-E-BPA-46; Tr. 938. Of equal importance to BPA is that this be done in a way that does not increase the rates of other customers, or place unreasonable levels of additional cost risk on those customers. *Id*. This context is made abundantly clear in a letter from BPA to the DSIs at the beginning of the negotiations that eventually led to the Compromise Approach agreement. *See* Cross-Examination Exh., WP-02-E-AL-05. In this letter, BPA's senior vice-president for the Power Business Line wrote:

> You have recently made us aware of your strong concern about the effect of rising market prices for electricity on the continued viability of aluminum plants in the PNW, and the attendant possible loss of high-paying jobs . . . In that light, we are prepared to discuss options that will help maintain plant operations and jobs, but that will not increase electricity rates to other Northwest consumers, including those served by publicly owned utilities and the residential and small farm consumers served by Northwest IOUs.

Id. It is unreasonable for the DSIs to argue that these principles now have no bearing on the level at which the aluminum price forecast is established under the Compromise Approach. As explained further below, the record indicates that establishing an aluminum price forecast above 74 cents/lb. will not serve to enhance DSI smelter survivability, but would place unnecessary cost risk on BPA's other customers.

BPA's proposal calls for upper and lower aluminum pivot points 6 cents/lb. above and below the indexed rate midpoint. Miller *et al*., WP-02-E-BPA-21, at 9. The lower pivot point is the point at which a further increase in the market price for aluminum results in an increase in the electricity price, and the upper pivot point is the point at which a further decrease in the price of aluminum results in a decrease in the electricity price. *Id*. Therefore, a 74 cent/lb. midpoint would result in a 68 cent/lb. lower pivot point (and a 19 mills/kWh BPA rate) and an 80 cent/lb. upper pivot point (and a 28.5 mills/kWh BPA rate). Under this scenario, a DSI that signed the Compromise Approach would not pay the equivalent of the fixed IPTAC rate of 23.5 mills/kWh until aluminum prices reached 74 cents/lb. Even assuming the DSIs were purchasing the other half of their load at market rates of 28 mills/kWh (which is almost 3 mills/kWh higher than the DSIs argue a flat block of power will cost in the market during the 2002-2006 period, *see* DSI Brief, WP-02-B-DS-01, at 33), and aluminum prices hover at 68 cents/lb. (19 mills/kWh), BPA's analysis suggests smelter survivability would not be threatened. Berwager *et al*., WP-02-E-BPA-09, at 13; Miller *et al*., WP-02-E-BPA-46, at 8.

The forecast range BPA is proposing gives the DSIs significant protection from downside aluminum prices that would threaten their survivability. Miller *et al*., WP-02-E-BPA-46, at 10. Conversely, a forecast set with an eye on the forward price protects BPA's other customers from indexed rate risks that could otherwise not be financially mitigated. *Id.* An aluminum price forecast midpoint above 74 cents/lb. cannot be justified from the evidence in the record concerning DSI smelter survivability, even if the consensus of the predictive aluminum forecasts in the record suggests that aluminum prices will equal or exceed 76 cents/lb. in the 2002-2006 period. The indexed rate concept was never intended to be used as an indirect means to lower the fixed rate price points of 23.5 and 25 mills/kWh, nor as a means to guarantee additional benefits to the DSIs. *Id*. at 11. At the higher aluminum prices predicted by the DSIs, survivability is not an issue, and BPA will not design its indexed rate so that those higher aluminum prices are necessary for BPA to recover its costs. *Id*.

The DSIs assert that BPA's proposal is inconsistent with the Compromise Approach agreement, because it fails to give "meaningful weight" to the predictive aluminum forecasts in the record, and that BPA's witness acknowledged at cross-examination that the DSI expert's forecast was reasonable. DSI Brief, WP-02-B-DS-01, at 44. Again, however, the fundamental principles around which the Compromise Approach agreement was negotiated were to enhance smelter survivability while not imposing additional costs on BPA's other customers. Miller *et al*., WP-02-E-BPA-46, at 3-4. BPA's proposal is to establish an aluminum price forecast on which to base the indexed rate midpoint that is approximately 2 cents/lb. above the forward price for aluminum, up to a maximum of 74 cents/lb. *Id*. at 4-6. A midpoint set as high as 74 cents/lb. is reflective of the potentially higher prices expected in the DSIs' own forecast and gives "meaningful weight" to that forecast, but the record demonstrates that a midpoint set above 74 cents/lb. is neither necessary to address smelter survivability nor consistent with BPA's principle of not imposing unreasonable cost risks on other customers. BPA agrees with the PPC's conclusion that the possibility of forecast error would expose BPA's other customers to significant risk. PPC Brief, WP-02-B-PP-01, at 61.

The DSIs cite a portion of the cross-examination transcript to support the conclusion that BPA's witness agreed that the aluminum price forecast of Wharton Econometric Forecasting Associates

Group (WEFA) (76.96 cents/lb.) and of the DSIs' expert, Mr. Robin Adams (base forecast of 78.5 cents/lb.) were reasonable. DSI Brief, WP-02-B-DS-01, at 44. What the BPA witness testified was that he believed Mr. Adams' forecast was "as reasonable as any other aluminum price forecast that's out there," Tr. 1009; and that the WEFA forecast was "more reasonable" compared to another independent forecast. Tr. 1011. In spite of DSI counsel's statement that he was using the term "reasonable" in the same sense that it was used in the Compromise Approach agreement, Tr. 1009, the colloquy between the BPA witness and DSI counsel on the issue clearly indicates the witness's testimony was in the context of examining the reasonableness of these predictive aluminum price forecasts *as* predictive forecasts and comparing each to the other, not whether the witness believed that such forecasts were "reasonable" under the Compromise Approach agreement. Tr. 1009-11.

In fact, the Compromise Approach agreement defines the rate case aluminum price forecast as being comprised of both forward price curves and "aluminum price forecasts provided to BPA by independent consultants." *See* Berwager *et al*., WP-02-E-BPA-09, Attachment 1. The BPA witness was not testifying to the reasonableness of any of the predictive aluminum price forecasts in this context, nor could he have, since predictive forecasts make up only one part of the "aluminum price forecast" defined in the Compromise Approach. In any case, Mr. Adams, as the expert witness retained by the DSIs, is not an "independent consultant," so while his forecast is informative and lends additional credence to the observation that the consensus of predictive forecasters is that aluminum prices will rise in the 2002-2006 period, it is neither the type of "aluminum price forecast" specified under the Compromise Approach agreement, nor independent.

The DSIs take exception to BPA's conclusion that Mr. Adams does not constitute an "independent consultant" under the Compromise Approach. DSI Ex. Brief, WP-02-R-DSI-01, at 8. *Id*. They argue that the mere fact that Mr. Adams was compensated by the DSIs for his work does not mean his opinions with respect to the future price of aluminum are not independent, and that BPA's position on this issue suggests BPA had a closed mind and never intended to weigh the evidence presented by the DSIs regarding the aluminum price forecast. *Id*. The DSIs state that BPA should find that the forecasts prepared by WEFA, CRU, and Mr. Adams were all prepared by independent consultants within the meaning of the Compromise Approach. *Id*. Whether Mr. Adams qualifies as an "independent consultant" within the meaning of the Compromise Approach is not ultimately important since BPA, in fact, has proposed to establish a range for the aluminum price forecast up to Mr. Adams's own median adjusted forecast of 74 cents/lb., based in part on Mr. Adams testimony. Additionally, as noted elsewhere, BPA's willingness to adopt an aluminum price forecast up to 2 cents/lb. above forward price quotes is due, in part, to the consensus among the predictive aluminum forecasts in the record, including that of Mr. Adams, that aluminum prices will move higher through the rate period.

Lastly, the DSIs argue that the aluminum market "backwardization" existing at the time the Draft ROD was published will result in BPA fixing the midpoint of the indexed rate at a level much below expected real aluminum prices, with the consequence that the DSIs will not realize any advantage from the indexed rate, and making the financial hedge particularly costly. *Id*. at 44-45. In fact, the DSIs' testimony acknowledges that while a backwardization is more frequently associated with increasing prices, that prices in some cases (35 percent using the example in the testimony) will fall. Adams, WP-02-E-DS-01, at 12-13. It is the prospect for a fall in prices during the time BPA is financially hedging its aluminum exposure that is of greatest concern to BPA. Miller *et al*., WP-02-E-BPA-46, at 4, 17. Although BPA views this risk as moderate, it does represent a risk nonetheless. Tr. 960-61. To the extent the DSIs are correct and the backwardization of the market is followed by rising aluminum prices, then the survivability concern will be mitigated in any case.

Nevertheless, BPA is mindful of the complexities of hedging the risks associated with the indexed rate, including any market anomalies that may be created by a backwardized aluminum market, and intends to lay off that risk in a timely and systematic manner that will be dictated in part by aluminum market conditions at the time indexed rate contracts are executed. *Id*.; Miller *et al*., WP-02-E-BPA-46, at 7. In this respect BPA agrees with the DSIs that there should be some flexibility regarding the timing of establishing the aluminum price forecast after contracts are signed. BPA intends to offer each DSI flexibility regarding the timing of establishing an indexed rate, which should also be advantageous to BPA from a risk management perspective. *Id*.

The IOUs argue that BPA's proposed design for the indexed IP rate places an unreasonable risk of cost shifts on other customer classes. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63-64. The IOUs argue that BPA has not accounted for this risk, that BPA is proposing to absorb the risk associated with the varying price of aluminum, and that ultimately BPA may be forced to try to turn to its transmission customers to cover the costs of that risk. *Id*. at 64. Similarly, PPC argues that the proposed indexed IP rate, unless fully hedged by BPA and priced to include the full cost of the hedge, represents a significant cost to BPA's public utility customers. PPC Brief, WP-02-B-PP-01, at 60-61.

BPA agrees with these parties that an unhedged indexed rate would expose BPA's other customers to unacceptable levels of risk, but BPA has made it very clear that it does not intend to carry through the rate period any of the aluminum price risk associated with an indexed rate tied to the price of aluminum. Miller *et al*., WP-02-E-BPA-46, at 3; Tr. 959-60. BPA's proposal is to establish an aluminum price forecast that is up to 2 cents/lb. above forward price quotes obtained at the time the DSI elects to purchase under an indexed rate, but BPA will not establish a forecast lower than 66 cents/lb. or higher than 74 cents/lb. Miller *et al*., WP-02-E-BPA-46, at 2-6. This basic construct allows BPA to strike a reasonable balance between smelter survivability concerns during times of low aluminum prices, and the concerns of other customers that they not be exposed to unreasonable cost risks associated with the indexed IP rate. BPA believes under these parameters that it can effectively lay off those risks. Tr. 962. PPC asserts there is no justification for the "two cent subsidy" and that it is inconsistent with the principle of offering a fully hedged rate with revenue equivalent to the fixed IP rate. PPC Brief, WP-02-B-PP-01, at 61. However, BPA believes that a spread of up to 2 cents/lb. is appropriately reflective of the general consensus that aluminum prices will improve through the rate period, but only to the extent necessary to meet the goal of enhancing smelter survivability, and at prices that will allow BPA to hedge this risk as soon as practicable to protect BPA's other customers from additional costs. Miller *et al*., WP-02-E-BPA-46, at 4. In addition, BPA plans to lay off all the risk associated with the indexed IP rate, Tr. 1046-47, including the 2 cent/lb. spread between the forward price and the indexed rate midpoint, in as timely a manner as possible. Tr. 993-94.

PPC also suggests that the floor rate, ceiling rate, and the slope must also be subject to adjustment, and that the cost of any options must be accounted for in the rate, in order to accurately reflect the cost of the hedge. PPC Brief, WP-02-B-PP-01, at 61. This is incorrect. The indexed rate parameters were designed to create a high probability of collecting revenues equivalent to the IPTAC rates of 23.5 and 25 mills/kWh over the five-year rate period. Miller *et al*., WP-02-E-BPA-21, at 9. A lower rate limit of 19 mills/kWh was selected to limit the risk that BPA would underrecover revenues during this period, but a lower limit higher than this would lose its value as a tool for the smelters to cope with periods of low aluminum prices. *Id.* An upper rate limit set five mills/kWh higher than the projected cost-of-service appropriately balances the upside revenue gain associated with rising aluminum prices and provides a reasonable assurance of recovering revenues equal to the IPTAC. *Id*. at 10. It is not necessary to adjust the lower and upper rate limits or the slope in order for BPA to fully or cost-effectively hedge its indexed rate risk. *Id*. Whether BPA will be required to execute any option contracts associated with any particular indexed IP will not be known until BPA seeks to actually hedge the rate. However, BPA anticipates that if it must take option positions in order to round out its hedge, that it will be able to do so at little or no net cost. Miller *et al.*, WP-02-E-BPA-46, at 8, 16. To the extent there is any net cost, this is part of the moderate time-risk element that BPA agreed to take on behalf of the DSIs. *Id.* at 4.

<u>Decision</u>

BPA's proposal for establishing an indexed IP rate for its aluminum smelter customers strikes an appropriate balance between the goal of enhancing smelter survivability and associated jobs during times of low aluminum prices, and the goal of not shifting additional risks associated with that proposal to other customers. To that end, BPA's aluminum price forecast for the midpoint of the indexed rate will be set up to 2 cents/lb. above forward prices, but not above 74 cents/lb.

<u>Issue 3</u>

Whether BPA is proposing to impermissibly set certain indexed IP rates outside the rate case.

<u>Parties' Position</u>

ICNU argues that BPA is proposing to establish indexed IP rates for its non-aluminum DSI customers outside the scope of this rate case. ICNU Brief, WP-02-B-IN-02, at 4. ICNU argues that the impermissibility of "deferral ratemaking" is most evident with regard to BPA's DSI customer Elf Atochem, and that BPA has committed to setting an indexed rate for this company outside the scope of the rate case. *Id*. ICNU argues that BPA is prohibited under section 7(i) of the Northwest Power Act from establishing rates without conducting a public process and following statutorily prescribed procedures. *Id*. at 5. ICNU argues that BPA is proposing to establish indexed rates for non-aluminum DSI customers absent a hearing and the establishment of a record concerning such rates in violation of established ratemaking procedures, thereby preventing any adequate opportunity for parties to comment on, refute, or rebut BPA's proposed rates. *Id*. ICNU recommends that the Administrator reject BPA's proposal regarding the non-aluminum DSI indexed rates, or in the alternative establish a section 7(i) process to allow public comment on such rates. *Id*. at 6.

No other party took a position on this issue.

BPA's Position

BPA is not proposing to establish any rates, including indexed rates for its non-aluminum DSI customers, outside the rate case. The rate that would apply to any non-aluminum DSI that is also offered the indexed rate option will be the applicable IPTAC rate, which is currently proposed to be 23.5 mills/kWh. Miller *et al*., WP-02-E-BPA-21, at 6. Under BPA's proposal, any indexed rate offered to a non-aluminum DSI must be structured to recover the same revenue values as the applicable IPTAC. *Id*. Under BPA's proposal, securing a reasonable assurance of a revenue stream equal to the applicable IPTAC rate would be achieved through a combination of the design of the indexed rate parameters, and if necessary, by financially hedging the transaction. Tr. 942. Therefore, the index and its parameters may be established outside the rate case, but only where the foregoing and other specific criteria are met, and only at BPA's discretion. Miller *et al*., WP-02-E-BPA-46, at 26. Finally, BPA anticipates that few, if any, non-aluminum DSIs will seek to have an indexed rate. *Id*.

Evaluation of Positions

ICNU states that BPA plans to work with the non-aluminum DSI companies to establish an undefined index for creating rates, and refers to this as "deferral ratemaking." ICNU Brief, WP-02-B-IN-02, at 4. ICNU has misconstrued BPA's indexed rate option proposal. In fact, BPA is not proposing to establish any rates outside the rate case, since under BPA's proposal any indexed rate must be fashioned around collecting the same revenues as BPA would collect from the customer under the applicable fixed IPTAC rate. Tr. 942. BPA has proposed that it will consider offering an indexed rate to non-aluminum DSI customers only where the proposed index possesses very specific attributes including: (1) it must represent a commodity in which there is sufficient competition and price transparency, evidenced by a commercially recognized price index; (2) the pricing methodology employed in the index must rely on multiple producers; (3) the index must be used commercially to set settlement terms between producers and consumers; and (4) the index must be capable of use for establishing longer-term prices and for hedging. Miller *et al*., WP-02-E-BPA-46, at 26. The primary purpose for these parameters is to ensure that BPA would be able to enter into a financial transaction that would provide offsetting cash flows to the revenues BPA would receive under the applicable flat, fixed IPTAC rate under the power sales contract with the DSI. Tr. 943.

ICNU argues that this "deferral ratemaking" is most evident with regard to the DSI Elf Atochem. ICNU Brief, WP-02-B-IN-02, at 4. ICNU cites some correspondence from Elf Atochem to BPA regarding the Compromise Approach agreement, in which Elf Atochem states it accepts the Compromise Approach provided that BPA would negotiate with Elf Atochem, among other things, "variable rates tied to the price of Elf Atochem products." *Id*. ICNU concludes from this, and from selective cites to the cross-examination transcript, that BPA has committed to set

Elf Atochem's rates outside the scope of this rate case. *Id*. This conclusion is incorrect for the reasons outlined above. In addition, as BPA witnesses stated at cross-examination, that while any negotiations with a non-aluminum DSI regarding the establishment of an indexed rate would not be subject to a public process,

> [t]he objective that BPA would have in that index rate is to assure that we would collect the cost-based revenue requirement that we would anticipate collecting with the fixed rate.

Tr. 942.

To this end, BPA has proposed four criteria for a non-aluminum DSI indexed rate that make it clear that BPA is not proposing to establish any rates outside the rate case. First, in order to ensure that BPA may hedge any commodity risk associated with the indexed rate if necessary, the proposed index must meet to BPA's satisfaction the criteria outlined in BPA testimony. Tr. 940; Miller *et al*., WP-02-E-BPA-21, at 6. Second, the resulting average rate collected over the rate period must be projected to recover the same revenues as the applicable IPTAC rate. *Id*. Third, because the indexed rate for BPA's DSI customers is being proposed to enhance the prospect of DSI survivability and the jobs associated with DSI operations, the requesting non-aluminum DSI must make a demonstration that their survivability is an issue and that BPA may help assist the survivability through the establishment of an indexed rate. Miller *et al*., WP-02-E-BPA-21, at 6; *see also* Tr. 948-49. And fourth, an indexed rate will be offered only at BPA's discretion. ICNU argues that BPA's proposal violates BPA's governing statutes because the Administrator's decisions regarding rates must be based on the record. ICNU Brief, WP-02-B-IN-02, at 5. However, as noted, BPA has clearly articulated in this rate case the conditions under which it will establish an indexed rate for its non-aluminum DSI customers, the most important of which is that any such rate will be established based on collecting revenues equivalent to the applicable IPTAC rate. ICNU has filed no testimony regarding these conditions.

ICNU argues in its brief on exceptions that the parameters BPA has established for creating a non-aluminum DSI indexed rate are inadequate, and that they do not address the rate design issues which BPA is required to determine in the rate case. ICNU Ex. Brief, WP-02-R-IN-01, at 8. As examples, ICNU lists that the determination of demand charges, load variance charges, billing determinants, and seasonal discounts all would be determined outside the rate case. *Id*. However, none of the items listed by ICNU would be part of an indexed rate. For example, as indicated in the proposed IP-02 rate schedule, there would be no separate demand or energy charges associated with any indexed rate or the IPTAC rates upon which they are based--there is only a single flat energy rate for each month, which would only vary by month as indicated in the proposed schedule, and depending on any variability in the commodity index selected. *See* Appendix 1, at 56, 84-86. Load variance charges under the IP-02 rate, when applicable, are dealt with for all DSI customers as a separate, independent charge in the rate schedule. *Id*. at 59. There would be no seasonal discounts with an indexed rate; the index provides the only variability available. And the only billing determinant applicable to such a rate would be kWhs. Essentially, there are no rate design or other rate elements other than the nature of the index to be used that would be decided bilaterally with the customer. Of course, the parameters of the indexed rate would be dictated by the requirement that BPA recover over the rate period revenues equal to or greater than the IPTAC rate.

Finally, the proposal to establish an indexed rate formula outside the rate case based on a rate established in the rate case is not unique. BPA's existing Variable Industrial Power Rate (VI-96) schedule is virtually identical to BPA's proposal in this rate case for its non-aluminum DSI customers. *See* WP-96-A-02, Appendix, at 48. Among other things, the variable rate formula under VI-96, which is available for that portion of DSI load used in primary metal reduction, is based on the IP-96 rate, but the individual rate formulas, including all rate parameters, are established for each customer at the time contracts are negotiated. *Id*.

Decision

BPA is not establishing rates for its non-aluminum DSI customers outside of this rate case, but rather will offer, at its discretion and under specified circumstances, indexed rates that are designed to recover revenues equivalent to the applicable IPTAC rate.

Issue 4

Whether BPA's proposal regarding the Indexed IP rate is discriminatory because BPA is offering indexed rates to only its DSI customers and not to non-DSI industries.

Parties' Positions

ICNU argues that BPA's proposal to offer indexed rates to only its DSI customers is arbitrary, capricious, an abuse of discretion, and not in accordance with the law. ICNU Brief, WP-02-E-IN-02, at 11. ICNU argues that the failure by BPA to offer comparable rates to industrial customers of public agencies is discriminatory, and BPA may not discriminate among similarly situated customers unless it can justify the distinction between DSI and non-DSI companies, and that BPA has failed to do so. *Id*. at 12-13. ICNU proposed that BPA should offer an indexed (also referred to as "variable") rate to all large industrial electric users in the Northwest based on the market price of their respective products. Wolverton, WP-02-E-IN-01, at 1. ICNU argues it is more important to provide a variable rate to the non-DSI industries than to the DSIs, because non-DSI industries comprise a substantially larger part of the economy, both in terms of breadth of geographic scope and in terms of number of employees, than do the DSIs. *Id*. at 7. ICNU testified that if BPA decides to hedge its aluminum price risk associated with the indexed rate proposal to the aluminum smelters, that adding the hedging of non-aluminum prices should reduce the risk faced by BPA by broadening the scope of the risk. *Id*. at 9. ICNU argues that BPA should either offer additional variable rates tied to price indices that reflect the commodities produced by industrial customers of public agencies, or withdraw its proposal to offer variable rates to the DSIs. ICNU Brief, WP-02-B-IN-02, at 14.

In its brief on exceptions ICNU recasts its argument, and argues that by failing to offer an indexed rate to ICNU industries BPA is discriminating not only against those industries, but against BPA public preference customers. ICNU Ex. Brief, WP-02-R-IN-01, at 5-6. They argue that BPA must consider and evaluate whether publicly owned utilities have a right to buy an indexed IP-type product for their industrial customers. *Id*. at 2. ICNU also argues that BPA's statutes prohibit undue discrimination "by implication," and that section 7(c) of the Northwest Power Act in particular provides support for the proposition that Congress intended DSI and non-DSI industries to be similarly situated with respect to rates. *Id*. at 4. ICNU also argues that BPA misconstrued in the Draft ROD its arguments regarding the application of *Association of Public Agency Customers v. BPA*, 126 F.3d 1158 (9th Cir. 1997)(APAC), and that BPA erroneously assumed ICNU argued in its initial brief that *APAC* required that BPA power rate decisions should be examined pursuant to the Transmission System Act. 16 U.S.C. §838-838(k).

The IOUs disagreed that BPA should offer variable rates to all large industrial electric users in the Northwest. Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-13, at 5. The IOUs argued that such an offering is unnecessary because the services provided by such a rate could be purchased elsewhere, and that industries would choose to purchase from BPA under such a rate only if BPA made an error of pricing. *Id*. The IOUs disagreed with ICNU that the failure to offer a variable rate to non-DSI industries would constitute impermissible discrimination. *Id*. at 6. They argued that the DSIs are a special class of customer under the Northwest Power Act and therefore, can and must be treated differently. *Id*.

BPA's Position

BPA's proposal to offer an indexed rate option to its DSI customers does not legally obligate BPA to provide an indexed rate option to non-DSI industries. The industrial customers of public agencies are not "similarly situated" to the DSIs, but even if they were, there is no anti-discrimination standard applicable to the Administrator's decisions regarding service to the DSIs. Nor is it clear that BPA could enter into a rate relationship of the nature proposed by ICNU with any retail industrial load other than the existing DSIs. Miller *et al*., WP-02-E-BPA-46, at 26; 16 U.S.C. §839c(d)(2). Even if BPA could adopt ICNU's proposal and establish distinct rates for non-DSI retail industrial load, there appears to be little advantage in such a rate proposal to the non-DSI industries or to BPA or its other customers. Miller *et al*., WP-02-E-BPA-46, at 26 *et seq*.

BPA agrees the ICNU industries are important to the region's economy, but ICNU's testimony does not provide any analysis of the effect of BPA power prices on the ability of the ICNU industries to continue to operate, or even show any general concern for the survivability of these industries absent a BPA-sponsored indexed rate. *Id*. at 27. In addition, BPA is proposing to serve the public utilities that serve the ICNU industries with FY 2002-2006 PF power rates that are far below market rates, and at average rates below those proposed for BPA's DSI customers. *Id*. at 29. This fact alone makes it difficult to comprehend how the ICNU industries are being discriminated against by BPA, and there is no apparent reason why these industries cannot propose to their serving utilities that they be offered a variable rate. *Id*.

Finally, BPA does not agree with ICNU that a strategy of a variable rate for multiple industries is a suitable means of diversifying BPA's indexed rate risk. *Id*. In fact, such a proposal would tend to intensify the effects of the business cycle on BPA's revenues, intensifying BPA's other market related risks in times of low or no economic growth. *Id*.

Evaluation of Positions

ICNU argued in its testimony that BPA should offer "variable rates to all large industrial electric users in the Northwest," Wolverton, WP-02-E-IN-02, at 1; but in its initial brief stated that BPA must offer a "comparable variable rate to industrial customers of public agencies." ICNU Brief, WP-02-B-IN-02, at 12-14. For purposes of this evaluation, BPA will assume that ICNU is arguing that BPA must offer an indexed rate option, similar to the proposed indexed IP rate option, to industrial customers of public agencies, and not to all large industrial electric users in the Northwest.

ICNU argues that BPA's failure to offer indexed rates to the industrial customers of public entities is arbitrary and capricious, since such failure constitutes undue discrimination against those industrial customers. ICNU Brief, WP-02-B-IN-02, at 11. ICNU's argument that BPA must offer an indexed rate to the industrial customers of public agencies is premised on ICNU's conclusion that the DSIs and the industrial customers of public agencies are "similarly situated." *Id*. at 12. ICNU argues that the DSIs have historically received unique treatment because of the initial 20-year power sales contracts offered to the DSIs under the Northwest Power Act, but that when those contracts or their replacements expire in September 2001, the industrial customers of public agencies will be similarly situated to DSIs and therefore must be offered a comparable variable rate, absent some justification from BPA for not offering them such a rate. *Id*. at 12-13.

ICNU's analysis is flawed. ICNU cites *Association of Public Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158 (9th Cir. 1997) (*APAC*) to support its contention that the industrial customers of public agencies and the DSIs will become "similarly situated" upon the expiration of BPA's initial contracts with the DSIs. ICNU Brief, WP-02-B-IN-02, at 12-13. ICNU's reliance on *APAC* is misplaced. In *APAC*, the issue before the court was whether section 6 of the Transmission System Act, 16 U.S.C. §838, §838d, precludes BPA from offering to wheel non-Federal power to the DSIs without also offering the same service to ICNU's members ("APAC" was the prior acronym for ICNU). *APAC*, at 1171. The issue concerned an express anti-discrimination provision in the Transmission System Act regarding BPA's provision of transmission wheeling services to its utility customers, but ICNU has not demonstrated how this analysis applies to its conclusion that if BPA offers an indexed rate option to the DSIs it must provide a comparable indexed rate option to the industrial customers of public agencies. BPA did not propose the indexed IP rate option under section 6 of the Transmission System Act. In any case, the court held that section 6 applied only to discrimination among utilities, and therefore did not apply to either the DSIs or the ICNU industries. *Id*.

The court then stated that even if section 6 of the Transmission System Act did apply to these entities, BPA's actions in offering wheeling contracts to the DSIs but not the ICNU industries would be fully justified under the "unjust, unreasonable, or unduly discriminatory or preferential" standard in the Federal Power Act. *See* 16 U.S.C. §824k(i)(1)(B)(ii). ICNU is correct that the court concluded that the DSIs and the ICNU industries were not "similarly situated," because of the ability of the DSIs to terminate their 1981 contract with BPA on one year's notice. However, as noted above, BPA is not proposing the indexed IP rate option under section 6 or any other provision in the Transmission System Act, and the Federal Power Act standard is applicable only to BPA's transmission rates, not its power rates or to the

Administrator's decisions regarding whether to offer power services to some customers and not others. ICNU argues in its brief on exceptions that this analysis erroneously assumes ICNU argued in its initial brief that BPA's rate proposal should be examined pursuant to the Transmission System Act. ICNU Ex. Brief, WP-02-R-IN-01, at 3. BPA understands ICNU's argument to be that under different circumstances (that is, where ICNU industries are similarly situated to DSIs), *APAC* indicates that anti-discrimination standards would apply to BPA's power ratemaking decisions. However, the fact remains that the only anti-discrimination provisions discussed by the court in *APAC* are those contained in the Transmission System Act and Federal Power Act with respect to transmission rates. Whether ICNU's reading of *APAC* is correct or not ultimately is irrelevant, since neither of those anti-discrimination standards applies to BPA power ratemaking decisions. *APAC's* analysis focused on ICNU's claim that its members were similarly situated to DSIs for purposes of BPA transmission service and rates, not on whether non-DSI industries could be similarly situated to DSIs for purposes of power service and rates from BPA. Therefore, the "similarly situated" analysis by the court has no application to BPA's proposal for service to the DSIs in this rate case. Even if it did, the court held that ICNU's members are not customers of BPA. *APAC*, 126 F.3d 1158, 1172.

Even if the "similarly situated" analysis did apply in this case, the fact that the initial long-term contracts (or their successors) offered to the DSIs in 1981 pursuant to section 5(d)(1)(B) of the Northwest Power Act (16 U.S.C. §839c(d)(1)(A)) expire in September 2001 does not automatically strip an existing DSI of its direct customer status under the Northwest Power Act. The Administrator has the discretion, but not the obligation, to continue to serve the DSIs directly after September 2001. *See infra*, at 15.5.3. Existing DSIs remain an exclusive class of industrial customers that the Administrator is authorized to serve directly. Even ICNU argued in *APAC* that its industrial customer members would be "similarly situated" in 2001 only if BPA no longer served the DSIs, not merely because BPA no longer had an obligation under section 5(d) of the Northwest Power Act to serve the DSIs. *APAC*, 126 F.3d 1158, 1172. Therefore, ICNU's conclusion that the DSIs and the industrial customers of public utilities will be "similarly situated" because the initial DSI contracts will expire in September 2001 is incorrect and not supported by *APAC*.

ICNU argues in its brief on exceptions that, in fact, it suggested in its initial brief that several power ratemaking provisions in BPA's statutes "by implication" prohibit undue discrimination. ICNU Ex. Brief, WP-02-R-IN-01, at 3. Specifically, ICNU cites sections 7(a) and 7(g) of the Northwest Power Act. 16 U.S.C. §839e(a)(1), §839e(g). ICNU notes that section 7(a), among other things, requires that BPA establish rates consistent with "sound business principles." However, ICNU does not explain how this clause in section 7(a) rises to the level of an anti-discrimination directive. To the contrary, as indicated elsewhere, BPA believes proposing variable rates for multiple industries would tend to intensify the effects of the business cycle, making BPA's other risk areas more susceptible in times of low or no economic growth. Miller *et al*., WP-02-E-BPA-46, at 27. Taking such action would not be consistent with "sound business principles." ICNU also notes that section 7(g) requires BPA to allocate certain power costs consistent with "generally accepted ratemaking principles." Again, ICNU fails to tie this clause of section 7(g) to BPA's indexed rate proposal in this case. In fact, section 7(g) applies only to the allocation of certain costs not otherwise allocable under the power rate directives in section 7 of the Northwest Power Act, and so has no application as a broader anti-discrimination standard.

In addition, ICNU now cites section 7(c) of the Northwest Power Act (16 U.S.C. §839e(c)(1)(B)) for the proposition that Congress intended the DSIs to be similarly situated to ICNU member industries with respect to rates, and that it is therefore appropriate to apply a traditional "discrimination" standard to analyze the rates BPA offers to the DSIs. ICNU Ex. Brief, WP-02-R-IN-01, at 4. Section 7(c)(2) provides that DSI rates set under that provision be "equitable in relation to the retail rates" charged by BPA's public preference customers to their industrial customers in the region. However, ICNU does not explain how this provision compels BPA to offer non-DSI industries the same type of rates offered to the DSIs. Section 7(c)(2) requires only that the rates under that section be based on the applicable PF rate, plus a typical margin applied by BPA's public preference customers to the rates they charge their industrial customers. The proposed fixed IPTAC rates have been established consistent with this provision, but ICNU reads more into section 7(c)(2) than is there when it argues that this provision also requires BPA to offer non-DSI industries an indexed rate.

ICNU also argues that BPA, through its failure to offer more widely an industrial indexed rate, not only is discriminating directly against non-DSI industries that are similarly situated to the DSIs, but that BPA is also discriminating against its public preference customers. ICNU Ex. Brief, WP-02-R-IN-01, at 5. ICNU contends that BPA is discriminating "against the one class of customers who have permanent, statutory, preference rights to federal power." *Id.* at 6. Principally, public preference gives BPA's public body and cooperative customers the right to have their net full requirements met by BPA before BPA makes sales to non-preference customers, but ICNU fails to draw any connection between this preference right and a right to an indexed rate. No party has argued that its preference rights have been violated in the way alleged by ICNU, and in fact no other party in the rate case has supported ICNU's position that BPA should offer non-DSIs an indexed rate. ICNU's attempt to invoke the preference provisions to get an indexed industrial rate for non-DSI industrial customers served by public agencies is completely unavailing, if for no other reason than no public preference customer supports ICNU's position.

ICNU's proposal also appears to be inconsistent with section 5(d)(2) of the Northwest Power Act. 16 U.S.C. §839c(d)(2). Section 5(d)(2) provides that "[t]he Administrator shall not sell electric power, including reserves, directly to new direct service industrial customers." Notwithstanding ICNU's statements to the contrary in its brief on exceptions, ICNU's proposal clearly contemplates the formulation by BPA of distinct retail industrial rates for non-DSI industries, with BPA's public utility customers acting as a mere conduit for delivery and billing purposes. ICNU states that the variable rates need not be offered directly to public agency industrial customers, but that BPA could allow the public agency customer to purchase the variable rate power on behalf of the industrial customer. ICNU Brief, WP-02-B-IN-02, at 14; ICNU Ex. Brief, WP-02-R-IN-01, at 2. This suggestion, however, would essentially make a sham of the prohibition contained in section 5(d)(2).

The prohibition on BPA entering into direct sales relationships with new industrial customers must be read to go beyond merely limiting its ability to deal directly with new industrial customers, as suggested by ICNU. If that were the only prohibition, there would be nothing to prevent BPA from establishing a direct retail rate relationship with any industrial customer in the Northwest as long as the power was delivered to the retail industrial customer through a third-party utility or marketer, with that third party also serving as the surrogate bill collector. ICNU is proposing that BPA create individualized retail level rates for the industrial customers of public agencies. *See* Wolverton, WP-02-E-IN-01, at 1 *et seq*. However, BPA's relationship with such industrial customers is limited by section 5(d)(2) to meeting the net requirements of its preference customers with industrial load at the applicable wholesale rate. In order to have any meaningful application, the prohibition in section 5(d)(2) must be read to preclude BPA from establishing a direct retail-level rate relationship with any industrial load other than with the DSIs that had BPA contracts at the time of enactment of the Northwest Power Act. The retail-level rates paid by the industrial customers of public utilities are a matter between the industrial customer and its serving public utility. The practical effect of ICNU's proposal, and its argument that the industrial customers of public agencies are "similarly situated" to the DSIs, is to boot-strap those industrial customers into quasi-DSI status customers. This is contrary to Congress's express intent in section 5(d)(2). *See also* H.R. Rep. No. 96-976, pt. 1, at 63 (1980).

ICNU goes on to argue that BPA has provided no justification for discriminating against the industrial customers of public agencies. ICNU Brief, WP-02-B-IN-02, at 13. They note that BPA conducted a survivability analysis only for the aluminum smelter DSIs, but that BPA has proposed also to offer indexed variable rates to any non-aluminum DSI. *Id*. They argue that BPA's survivability standard could just as easily be applied to industrial customers of public agencies, and that because they make up a substantially larger part of the economy, it is more important to provide a variable rate to such non-DSI industries than it is to provide a variable rate to the DSIs. *Id*. 13-14. As outlined above, the industrial customers of public agencies are not "similarly situated" to the DSIs, and even if they were, the anti-discrimination provisions of the FPA do not apply in this case. BPA has no obligation, and perhaps no statutory authority, to offer the industrial customers of public agencies an indexed rate option.

With respect to ICNU's observation that BPA did not conduct any survivability analysis for non-aluminum DSIs, BPA proposed that the indexed rate will be made available to non-aluminum DSIs as a tool to aid their survival during times of low product prices, Miller *et al*., WP-02-E-BPA-21, at 6, and that any non-aluminum DSI that requested an indexed rate from BPA would need to demonstrate to BPA that its survivability was an issue and that an indexed rate would help assist its survivability. Tr. 949. Even if the industrial customers of public agencies were similarly situated to DSIs, ICNU failed to provide any analysis of the effect of BPA power rates on the ability of the ICNU industries to continue to operate, or even show any general concern for the survivability of the ICNU industries absent such a rate proposal from BPA. Miller *et al.*, WP-02-E-BPA-46, at 27. In addition, BPA established that proposing variable rates for multiple industries would tend to intensify the effects of the business cycle, making BPA's other risk areas more susceptible in times of low or no economic growth. *Id*. at 29. This would very likely place greater pressure on BPA to meet its cost recovery and Treasury repayment obligations. *Id*.

Finally, BPA is proposing to provide power in the 2002-2006 rate period to many utilities that serve the ICNU industries at prices that are far below market rates, and at average rates below those charged to BPA's DSI customers. *Id*. In addition, BPA has proposed a cost-based indexed PF rate available to the utilities serving many ICNU member industries. *Id*. These facts alone demonstrate that the industrial customers of public agencies are not being discriminated against by BPA vis-à-vis the DSIs, even if a discrimination standard applied.

<u>Decision</u>

The industrial customers of public entities are not "similarly situated" to the DSIs, and BPA's proposal to offer indexed rates to the DSIs and not the industrial customers of public entities does not constitute undue discrimination and is not arbitrary or capricious.