INTERPRETATION AND IMPLEMENTATION OF BPA'S 2002 GENERAL RATE SCHEDULE PROVISIONS REGARDING APPLICATION OF THE LOAD-BASED AND FINANCIAL-BASED COST RECOVERY ADJUSTMENT CLAUSES TO THE RESIDENTIAL LOAD (RL-02) AND PF EXCHANGE SUBSCRIPTION RATE SCHEDULES

ADMINISTRATOR'S DECISION RECORD

Bonneville Power Administration
U.S. Department of Energy

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INTRODUCTION

This Decision Record addresses the interpretation and implementation of BPA's General Rate Schedule Provisions (GRSPs). The GRSPs establish BPA's Load-Based and Financial-Based Cost Recovery Adjustment Clauses (LB and FB CRACs), which apply to the Residential Load (RL) and PF Exchange Subscription (PFXS) rate schedules. The issue presented is the manner in which the LB and FB CRACs apply to the RL and PFXS rates where the power benefit portion of BPA's Residential Exchange Settlement Agreements with investor-owned utilities (IOUs) is converted to cash upon termination of the Firm Power Block Sales Agreement under section 16 of that Agreement. In order to fully understand this issue, it is helpful to understand BPA's initial development of the REP Settlements with regional investor-owned utilities (IOUs) and BPA's 2002 Wholesale Power Rate Proposal. A review of such development follows.

BACKGROUND

BPA was created in 1937 to market electric power generated at Bonneville Dam, and to construct and operate facilities for the transmission of power. 16 U.S.C. § 832-832l (1994 & Supp. III 1997). Since that time, Congress has directed BPA to market power generated at additional facilities. *Id.* § 838f. Currently, BPA markets power generated at thirty Federal hydroelectric projects, and several non-Federal projects. BPA also owns and operates approximately 80 percent of the Pacific Northwest's high-voltage transmission system. In 1974, BPA became a self-financed agency that no longer receives annual appropriations. *Id.* § 838i. BPA's rates must therefore produce sufficient revenues repay all Federal investments in the power and transmission systems, and to carry out BPA's additional statutory objectives. *See id.* §§ 832f, 838g, 838i, and 839e(a).

In the 1970's, threats of insufficient resources to meet the region's electricity demands led to passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839, *et seq.* (1994 & Supp. III 1997). In that Act, Congress, among other things, directed BPA to offer new power sales contracts to its customers. *Id.* §§ 839c, 839c(g). While Congress provided that BPA's public agency customers (preference customers) and investor-owned utility customers (IOUs) had a statutory right for service from BPA to meet their net requirements loads, Congress did not provide such a right to BPA's direct service industrial customers (DSIs). BPA was provided the authority, but not the obligation, to serve the DSIs' firm loads after the expiration of their power sales contracts in 2001. *See id.* §§ 839c(b)(1), 839d. Congress also established the Residential Exchange Program, which, as discussed in greater detail below, provides Pacific Northwest utilities a form of access to the benefits of low-cost Federal power. *Id.* § 839c(c).

A. The Residential Exchange Program (REP)

Section 5(c) of the Northwest Power Act established the REP. *Id.* § 839c(c). Under the REP, a Pacific Northwest electric utility (either a publicly owned utility, an IOU or other entity authorized by state law to serve residential and small farm loads) may offer to sell power to BPA at the utility's average system cost (ASC). *Id.* § 839c(c)(1). BPA purchases such power and, in exchange, sells an equivalent amount of power to the utility at BPA's PF Exchange rate. *Id.* The amount of the power exchanged equals the utility's residential and small farm load. *Id.* In past practice, no actual power sales have taken place. Instead, BPA provided monetary benefits to the utility based on the difference between the utility's ASC and the applicable PF Exchange rate multiplied by the utility's residential load. These monetary benefits must be passed through directly to the utility's residential and small farm consumers. *Id.* § 839c(c)(3). While REP benefits have previously been monetary, the Northwest Power Act also provides for the sale of actual power to exchanging utilities in specific circumstances. Pursuant to section 5(c)(5) of the Northwest Power Act, in lieu of purchasing any amount of electric power offered by an exchanging utility, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to the utility as part of an exchange sale. *Id.* § 839c(c)(5). However, the cost of the acquisition must be less than the cost of purchasing the electric power offered by the utility. *Id.* In these circumstances, BPA acquires power from an in lieu resource and sells actual power to the exchanging utility.

Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers and other regional parties. A utility's ASC is the sum of a utility's production and transmission-related costs (Contract System Costs) divided by the utility's system load (Contract System Load). A utility's system load is the firm energy load used to establish retail rates. BPA's current ASC Methodology was established in 1984. BPA has recognized, however, that the ASC Methodology can be revised. BPA's current ASC Methodology uses a "jurisdictional approach" in determining utilities' ASCs, which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. These data provide the starting point for BPA's determination of the ASC of each utility participating in the REP. Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs.

The schedule for filing and reviewing a utility's ASC is established in the 1984 ASC Methodology, which provides that "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the utility shall file a preliminary Appendix 1, setting forth the costs proposed by the utility and shall deliver to BPA all information initially provided to the state commission." The filing includes all testimony and exhibits filed in the retail rate proceeding. Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. BPA then has 210 days to review the filing and issue a report signed by the Administrator. During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. BPA makes adjustments as necessary.

The REP has traditionally been implemented through Residential Purchase and Sale Agreements (RPSAs), which were executed in 1981. Between 1981 and the present, Residential Exchange Termination Agreements have been negotiated with all of the previously active exchanging utilities except Montana Power Company (MPC). MPC continues to be in "deemer" status. When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. By doing so, it avoids making actual monetary payments to BPA. The amount that the utility would otherwise pay BPA is tracked in a "deemer account." At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA under an existing or new RPSA. The issue of deemer balances with IOUs is currently in dispute. Regional utilities are eligible to participate in the REP again beginning July 1, 2001, except for those utilities that have previously executed settlement agreements for terms extending beyond July 1, 2001.

B. The Comprehensive Review of the Northwest Energy System

In early 1996, the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. *See* Comprehensive Review of the Northwest Energy System, Final Report, December 12, 1996 (Final Report). The governors appointed a 20-member Steering Committee that was broadly representative of the various stakeholders in the power system to study that system and make recommendations about its transformation. *Id.* Each governor had a representative on the Steering Committee to make certain the public was educated about and involved in the Comprehensive Review. *Id.* In establishing the review, the governors stated:

The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same tine assuring the region of an adequate, efficient, economical and reliable power system.

Id. In 1996, the Steering Committee held 30 daylong meetings. *Id.* In addition, almost 400 people were involved in more than 100 meetings of various work groups reporting to the Steering Committee. *Id.* Hundreds of citizens attended the 10 public hearings that were held throughout the region on the Committee's draft report. *Id.* More than 700 written comments were received. *Id.* The Final Report was the product of that work. *Id.*

The Final Report noted that the electricity industry in the United States is in the midst of significant restructuring. *Id.* This restructuring is the product of many factors, including national policy to promote a competitive electricity generation market and state initiatives in California, New York, New England, Wisconsin and elsewhere to open retail electricity markets to competition. *Id.* This transformation is moving the industry away from the regulated monopoly structure of the past 75 years. *Id.* Today the region is served by individual utilities, many of which control everything from the power plant to the delivery of power to the region's homes or businesses. *Id.* In the future, the region may have a choice among power suppliers that deliver their product over transmission and distribution systems that are operated independently as common carriers. *Id.* There is much to be gained in this transition. *Id.* Broad competition in the electricity industry that extends to all consumers could result in lower prices and more choices about the sources, variety and quality of their electrical service. *Id.*

The Final Report also noted that there are risks inherent in the transition to more competitive electricity services. *Id.* Merely declaring that a market should become competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared. *Id.* It is entirely possible to have deregulation without true competition. *Id.* Similarly, the reliability of the region's power supply could be compromised if care is not taken to ensure that competitive pressures do not override the incentives for reliable operation. *Id.* How competition is structured is important. *Id.* It is also important to recognize the limitations of competition. *Id.* Competitive markets respond to consumer demands, but they do not necessarily accomplish other important public policy objectives. *Id.* The Northwest has a long tradition of energy policies that support environmental protection, energy-efficiency, renewable resources, affordable services to rural and low-income consumers, and fish and wildlife restoration. *Id.* These public policy objectives remain important and relevant. *Id.* The Final Report states that given the enormous economic and environmental implications of energy, these public policy objectives need to be incorporated in the rules and structures of a competitive energy market. *Id.*

The Final Report stated that, in some respects, the transition to a competitive electricity industry is more complicated in the Northwest because of the presence of BPA. *Id.* BPA is a major factor in the region's power industry, supplying, on average, 40 percent of the power sold in the region and controlling more than half the region's high-voltage transmission. *Id.* BPA benefits from the fact that it markets most of the region's low-cost hydroelectric power. *Id.* It is hampered by the fact that it has high fixed costs, including the cost of past investments in nuclear power and the majority of the costs for salmon recovery. *Id.* As a wholesale power supplier, BPA is already fully exposed to competition and is struggling to reduce its costs so that it can compete in the market. *Id.* The transition to a competitive electricity industry raises many issues for the BPA and the region. *Id.* In the near term, how can BPA continue to meet its financial and environmental obligations in the face of intense competitive pressure? *Id.* In the longer-term, when market prices rise and some of BPA's debt obligations have been retired, how can the Northwest retain the economic benefits of its low-cost hydroelectric power when the rest of the country is paying market prices? *Id.* And finally, what is the appropriate role of a Federal agency in a competitive market? *Id.*

The Final Report noted that while participants on the Comprehensive Review Steering Committee represented, by design, many divergent interests, they were fundamentally interconnected through one unifying value. *Id.* Collectively, they share an abiding interest in the stewardship of a great regional resource -- the Columbia River and its tributaries. *Id.* The river is the link that brought all the parties together and unites them in a single, overriding goal. *Id.* That goal is to protect and enhance the assets of this great natural resource for the people of the Pacific Northwest. *Id.*

The Final Report stated that the Federal power system in the Pacific Northwest has conferred significant benefits on the region for more than 50 years. *Id.* The availability of inexpensive electricity at cost has supported strong economic growth and helped provide for other uses of the Columbia River, such as irrigation, flood control and navigation. *Id.* The renewable and non-polluting hydropower system has helped maintain a high quality environment in the region. *Id.* But while the power system has produced significant benefits, these benefits came at a substantial cost to the fish and wildlife resources of the Columbia River basin. *Id.* Salmon and steelhead populations had been reduced to historic lows, and many runs were about to be listed under the Federal Endangered Species Act. *Id.* Resident fish and wildlife populations had also been affected. *Id.* Native Americans and fishery-dependent communities, businesses and recreationists had suffered substantial losses due in significant part to construction and operation of the power system. *Id.* The region's ability to sustain its core industries, support conservation and renewable resources, and restore salmon runs would be clearly threatened if the region cannot reach a consensus regional position to bring to the national electricity restructuring debate. *Id.* Without a sustainable and financially healthy power system, funding for fish and wildlife restoration could be jeopardized. *Id.*

The Final Report noted that the Governors of Idaho, Montana, Oregon and Washington, in their charge to the Comprehensive Review, and the Steering Committee in their deliberations, recognized that the electricity industry is changing, whether the region likes it or not. *Id.* The Comprehensive Review was not an initiation of change, but a response to change. *Id.* It was an effort to shape that change, to the extent shaping is possible, to ensure that the potential benefits of competition are achieved and equitably shared, environmental goals are met, and the benefits of the hydroelectric system are preserved for the Northwest. *Id.* The region's ability to shape the change in the Northwest electricity industry depends on its ability to develop a regional consensus. *Id.* If the Comprehensive Review failed to result in a consensus for regional action, the electricity industry would still be restructured. *Id.* A return to the historical industry structure is not an option. *Id.* Many of the comments received during the public hearing process on the Steering Committee's draft recommendations made it clear that this was not a widely appreciated fact. *Id.*

The Final Report summarized the Steering Committee's goals and proposals. The Steering Committee's goals for Federal power marketing were to: (1) align the benefits and risks of access to existing Federal power; (2) ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists while not compromising the security or tax-exempt status of BPA's third-party debt; and (3) retain the long-term benefits of the system for the region. *Id.* The recommendation was also intended to be consistent with emerging competitive markets and regional transmission solutions. *Id.* The mechanism proposed to accomplish these goals was a subscription system for purchasing specified amounts of power at cost with incentives for customers to take longer-term subscriptions. *Id.* Public utility customers with small loads would be able to subscribe under contracts that would accommodate minor load growth. *Id.* Subscriptions would be available first to regional customers a specified multiparty priority order, starting with preference customers, then the DSIs and the residential and small farm customers of the IOUs participating in the REP, followed by other regional customers. *Id.* Non-regional customers could subscribe after in-region customers. *Id.* Within each phase of the subscription process, longer-term contracts would have priority over shorter-term contracts if the system were oversubscribed. *Id.*

With regard to the REP, the Final Report noted that as a result of the Northwest Power Act, Northwest utilities have the right to sell to BPA an amount of power equal to that required to serve their residential and small farm customers at the utilities' average system costs and receive an equal amount of power at BPA's average system cost. *Id.* In reality, this is an accounting transaction. *Id.* No power is actually delivered. *Id.* This was intended to be a mechanism to share the benefits of the low-cost Federal hydropower system with the residential and small farm customers of the region's IOUs. *Id.* As a result of decisions made by BPA in its 1996 rate case, those benefits were reduced. *Id.* The Steering Committee acknowledged that the residential and small farm consumers of exchanging IOUs would be adversely affected by the reduction of exchange benefits. *Id.* Congress intervened for one year to stabilize the exchange benefits. *Id.* However, on October 1, 1997, there would be rate increases to the residential and small farm customers of the exchanging utilities. *Id.* The Steering Committee encouraged the parties to continue settlement discussions and to explore other paths to ensure that residential and small farm loads receive an equitable share of Federal benefits. *Id.*

C. BPA's Power Subscription Strategy

The concept of power subscription came from the Comprehensive Review of the Northwest Energy System, which, as noted above, was convened by the governors of Idaho, Montana, Oregon, and Washington to assist the Northwest through the transition to competitive electricity markets. The goal of the review was to develop recommendations for changes in the region's electric utility industry through an open public process involving a broad cross-section of regional interests. In December 1996, after over a year of intense study, as noted above, the Comprehensive Review Steering Committee released its Final Report. The Final Report recommended that BPA capture and deliver the low-cost benefits of the Federal hydropower system to Northwest energy customers through a subscription-based power sales approach. In early 1997, the

Governor's representatives formed a Transition Board to monitor, guide, and evaluate progress on these recommendations.

Public process is integral to BPA's decisionmaking. With the changing marketplace for electric power, there is considerable regional interest in defining how and to whom the region's Federal power should be sold. The public was involved at several levels during the development of BPA's Power Subscription Strategy. In addition to the public meetings held specifically on Subscription, BPA sought input from a wide range of interested and affected groups and individuals. BPA collaborated with Northwest Tribes, interest groups, Congressional members, the Department of Energy (DOE), the Administration, and BPA's customers to resolve issues, understand commercial interests, and develop strong business relationships.

In early 1997, BPA and the Pacific Northwest Utilities Conference Committee (PNUCC) invited 2800 interested parties throughout the Pacific Northwest to help further define Subscription. The collaborative effort to design a Subscription contract process began with a public kickoff meeting on March 11, 1997. At this meeting, a BPA/customer design team presented a proposed work plan, including a description of the environmental coverage for Subscription. An important element of the work plan was the formation of a Subscription Work Group. The Work Group, which normally met in Portland twice a month from March 1997 through September 1998, was open to the public. On average, 40-45 participants--representing customers, customer associations, Tribes, State governments, public interest groups, and BPA--attended. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation.

Over 18 months, BPA, its customers and other interested parties discussed and clarified many Subscription issues. During this time, BPA and the public confirmed goals, defined issues, developed an implementation process for offering Subscription, and developed proposed product and pricing principles. The following is a chronology of events.

On March 11, 1997, a public meeting was held in Portland to kick off the Federal Power Marketing Subscription development process. The following topics were discussed at this meeting: the role of the Regional Review Transition Board in the Subscription process; the Draft Work Plan that was developed to guide the development process; the issues that relate to the Subscription process that need to be addressed; and the National Environmental Policy Act (NEPA) strategy for this effort. The Work Plan identified a "self-selected" work group to lead this effort (anyone eligible to participate).

On March 18, 1997, a "Federal Power Marketing Subscription" web site was established at BPA to help disseminate information about the Subscription Process.

On March 19, 1997, the Federal Power Subscription Work Group held its first meeting in Portland, Oregon. The Work Group held a total of 33 meetings (approximately two per month), ending on September 22, 1998.

On September 9, 1997, a Progress Report was presented to the Transition Board.

On November 25, 1997, an update meeting for stakeholders was held in Spokane to discuss progress to date and next steps. A summary of the meeting, along with the meeting handout/slide presentation and concerns/issues raised, was posted to the web site.

In January 1998, an article entitled "*Subscription Process Underway*" was published in the BPA Journal, (January 1998).

On April 30, 1998, BPA's Power Business Line (PBL) established a web site to disseminate information about a customer group's Slice of the System Proposal. The Subscription Work Group evaluated the Slice proposal, and the proposal as modified by BPA continued to be developed in a subgroup through January 1999. BPA's pricing of the Slice product was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's Record of Decision (ROD), WP-02-A-02.

In June 1998, as part of the Issues '98 process, BPA published Issues '98 Fact Sheet #3: Power Markets, Revenues, and Subscription. Issues '98 (June/Oct. 1998). The fact sheet discussed implementation approaches being considered by the Subscription Work Group so participants in the Issues '98 process could comment. As part of Issues '98 BPA conducted a series of meetings around the region. Issues related to Subscription were key topics in the discussions at those meetings. The public comment period for Issues '98 closed June 26, 1998.

On June 8, 1998, BPA's PBL established a web site to disseminate information about development of the power rates that would be used in the Subscription contracts beginning October 1, 2001. Preliminary discussions regarding development of the power rates occurred in a series of informal public meetings and continued in workshops before BPA's initial proposal was published in early 1999.

On June 18, 1998, the third Subscription public meeting was held in Spokane to present, discuss, and collect comments on the various components related to Subscription. The meeting slide presentation and summary of the meeting were posted to the web site.

On September 18, 1998, BPA released its Power Subscription Strategy Proposal for public comment. Accompanying the proposal was a press release entitled "Spreading Federal Power Benefits" and a Keeping Current publication entitled "Getting Power to the People of the Northwest, BPA's Power Subscription Proposal for the 21st Century." Keeping Current (Sept. 1998). On September 25th, an electronic version of the BPA Power Product Catalog was posted to the web site.

On September 22, 1998, the Federal Power Subscription Work Group held its final meeting in Portland, Oregon.

Subscription issues were discussed at the "Columbia River Power and Benefits" conference on September 29, 1998, in Portland, Oregon. Over 250 people attended. Conference notes were posted to BPA's web site.

On September 30, 1998, BPA's Energy Efficiency organization established a web site to help disseminate information on the proposal for a Conservation and Renewable Discount. Development of the discount continued in a series of meetings through January 1999. Development of the discount was part of BPA's initial power rate proposal and was also included in BPA's 2002 Final Power Rate Proposal, Administrator's ROD, WP-02-A-02.

The public was invited to participate in two comment meetings on the Subscription Proposal; one in Spokane, Washington, on October 8, 1998; the other in Portland, Oregon, on October 14.

BPA developed the Power Subscription Strategy Proposal after considering the efforts of the Subscription Work Group, public comments on Subscription, and the broad information from Issues '98. The Proposal incorporated the information received from customers, Tribes, fish and wildlife interest groups, industries and other constituents. It laid out BPA's strategy for retaining the benefits of the Federal Columbia River Power System (FCRPS) for the Pacific Northwest after 2001. The comment period on the proposal closed October 23, 1998, although all comments received after that date were considered in the Power Subscription Strategy ROD and the NEPA ROD.

During the spring and summer of 1998, BPA conducted extensive public meetings with all interested parties regarding the development of BPA's Power Subscription Strategy. At the conclusion of these lengthy discussions, on September 18, 1998, BPA released a Power Subscription Strategy Proposal for public review. During the comment period BPA received nearly 200 responses to the proposal comprising nearly 600 pages of comments. After review and analysis of these comments, BPA published its final Power Subscription Strategy on December 21, 1998. *See* Power Subscription Strategy, and Power Subscription Strategy, Administrator's ROD. At the same time, the Administrator published a National Environmental Policy Act (NEPA) ROD that contained an environmental analysis for the Power Subscription Strategy. This NEPA ROD was tiered to BPA's Business Plan ROD (August 15, 1995) for the Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995). The purpose of the Subscription Strategy is to enable the people of the Pacific Northwest to share the benefits of the FCRPS after 2001 while retaining those benefits within the region for future generations.

The Subscription Strategy also addresses how those who receive the benefits of the region's low-cost Federal power should share a corresponding measure of the risks. The Subscription Strategy seeks to implement the subscription concept created by the Comprehensive Review in 1996 through contracts for the sale of power and the distribution of Federal power benefits in the deregulated wholesale electricity market. The success of the Subscription process is fundamental to BPA's overall business purpose to provide public benefits to the Northwest through commercially successful businesses.

The Subscription Strategy is premised on BPA's partnership with the people of the Pacific Northwest. BPA is dedicated to reflecting their values, to providing them benefits and to expanding and spreading the value of the Columbia River throughout the region. In this respect, the Strategy had four goals:

> Spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region;
>
> Avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions;
>
> Allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and
>
> 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.

The Power Subscription Strategy describes BPA decisions on a number of issues. These include the availability of Federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. The Power Subscription Strategy discussed some issues that would not be finally decided in the Strategy. Most of these issues were decided in BPA's 2002 power rate case, although some were decided in other forums, such as the transmission rate case, which concluded recently. For example, while the Strategy documents BPA's intention to implement a rate discount for conservation and renewable resources, the final design of that discount was developed in BPA's 2002 power rate case. Other issues to be decided in the 2002 power rate case include the design and application of the CRAC, which rates apply to which sales, and the design of the Low Density Discount (LDD). Customers raised issues regarding the application of other customers' non-Federal resources to serve regional load. These resource issues involve factual determinations under section 3(d) of the Act of August 31, 1964, P.L. 88-552 (Regional Preference Act), and section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), which BPA could not address in the Power Subscription Strategy and which were not made a part of the decisions in the Subscription Strategy ROD.

While BPA's Power Subscription Strategy did not establish any rates or rate designs, rate design approaches identified in the Power Subscription Strategy were part of BPA's initial power rate proposal, which was published in 1999. The comments received during the Subscription public process regarding the various rate-related issues were addressed in BPA's 2002 power rate case, which included extensive opportunities for public involvement.

BPA's Power Subscription Strategy provided a framework for the 2002 power rate case and Subscription power sales contract negotiations. The Subscription window was to remain open 120 days after the 2002 Final Power Rate Proposal, Administrator's ROD, was signed by the BPA Administrator, providing relatively certain information to potential purchasers regarding rates.

One element the Power Subscription Strategy proposal was a settlement of the REP for regional IOUs for the post-2001 period. The Power Subscription Strategy proposed that IOUs may agree to a settlement of the REP in which they would be able to receive benefits equivalent to a purchase of a specified amount of power under Subscription for their residential and small farm consumers at a rate expected to be approximately equivalent to the PF Preference rate. Under the proposed settlement, residential and small farm loads of the IOUs would be assured access to the equivalent of 1,800 aMW of Federal power for the FY 2002-2006 period and 2,200 aMW of Federal power for the FY 2007-2011 period.

The Power Subscription Strategy noted that BPA would set the physical and financial components of the Subscription amount, by year, in the negotiated Subscription settlement contracts. Any cash payment would reflect the difference between the market price of power forecasted in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads would be in equal hourly amounts over the period.

The Power Subscription Strategy proposed that BPA would offer five-year and 10-year Subscription settlement contracts for the IOUs. Under both contracts, the Subscription Strategy proposed that BPA would offer and guarantee 1,800 aMW of power and/or financial benefits for the FY 2002-2006 period. At least 1,000 aMW would be met with actual BPA power deliveries. The remainder could be provided through either a financial arrangement or additional power deliveries, depending on which approach was most cost-effective for BPA. The IOUs' settlement of rights to request REP benefits under section 5(c) of the Northwest Power Act would be in effect until the end of the contract term. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997).

Under the 10-year settlement contract, in addition to the benefits provided during the first five years, BPA proposed to offer and guarantee 2,200 aMW of power or financial benefits for the FY2007-2011 period. BPA intended for this 2,200 aMW to be comprised solely of power deliveries. The IOUs' settlement of rights to request REP benefits under section 5(c) would be in effect until the end of the 10-year term of the contract. In the event of reduction of Federal system capability and/or the recall of power to serve its public preference customers during the terms of the five-year and 10-year contracts, BPA would either provide monetary compensation or purchase power to guarantee power deliveries.

In summary, residential and small farm loads of the IOUs could receive benefits from the Federal system through one of two ways. An IOU could participate in the established

REP or it could participate in a settlement of the REP through Subscription. If an IOU chose to request REP benefits under section 5(c), then the Subscription settlement amount for all the IOUs would be reduced by the amount that would have gone to the exchanging utility.

D. Power Subscription Strategy Supplemental ROD

As noted above, on December 21, 1998, the BPA Administrator issued a Power Subscription Strategy and accompanying ROD, which set the agency's PBL on a course to establish power rates and offer power sales contracts in anticipation of the expiration of current contracts and rates on September 30, 2001. The Strategy and ROD were the culmination of many public processes that came together to form the framework to equitably distribute in the Pacific Northwest the electric power generated by the FCRPS.

BPA's 1998 Power Subscription Strategy served to guide BPA in accomplishing its goals. After adoption of the Strategy, however, developments occurred that prompted BPA to seek, in some instances, additional comment from customers and constituents on new issues. The Strategy contemplated further public processes to implement its goals. BPA's 2002 power rate case, ongoing since August 1999, was completed on May 8, 2000. BPA and its customers continued discussions on power products and power sales contract prototypes, and the Slice of System product was further defined. In a December 2, 1999, letter, BPA sought comment from customers and constituents on some of these new issues, specifically, the length of the Subscription window for power sales contract offers, the actions required of new small utilities during this window to qualify for firm power service, and new developments with respect to General Transfer Agreements. Other issues arose independently, such as new large single loads (NLSL) under the Northwest Power Act, duration of the new power sales contracts, and a new contract clause regarding corporate citizenship. BPA also undertook a comment process on the amount and allocation of power and financial benefits to provide the IOUs on behalf of their residential and small farm consumers. On November 17, 1999, BPA sent a letter to all interested parties requesting comments on two specific issues: (1) whether the amount of the proposed IOU settlement should be increased by 100 aMW from 1800 aMW to 1900 aMW for the FY 2002-2006 period; and (2) the manner in which the settlement amount should be allocated among the individual IOUs.

1. Total Amount of IOU Settlement Benefits

BPA's intent in the Power Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region. The Subscription Strategy enabled the benefits of the FCRPS to flow throughout the region, whether currently served by publicly owned or privately owned utilities.

The Power Subscription Strategy provided that residential and small farm loads of the IOUs, through settlement of the REP, would be provided access to the equivalent of 1800 aMW of Federal power for the FY 2002-2006 period. At least 1000 aMW of the 1800 aMW would be served with actual BPA power deliveries. The remainder would be provided through either a financial arrangement or additional power deliveries depending on which approach was most cost-effective for BPA.

The four Pacific Northwest state utility commissions (Commissions), in a letter dated July 23, 1999, requested that BPA increase the amount of the settlement from 1800 aMW to 1900 aMW for the FY 2002-2006 period. This request was made in order for the Commissions to arrive at a joint recommendation for allocating the settlement benefits among the IOUs for both the FY 2002-2006 and FY 2007-2011 periods. Many parties supported this increase for many reasons, including: (1) the increase is a wise policy decision and it helps to ensure that the regional interest in the system and preserving the system as a valuable benefit in the Northwest will be shared as broadly as possible among the region's voters; (2) the increase is appropriate in order for BPA to achieve the stated Subscription Strategy goal to "spread the benefits of the Federal Columbia River Power System as broadly as possible, with special attention given to the residential and rural customers of the region," *see* Power Subscription Strategy at 5; (3) the increase creates a fair and reasonable settlement to the REP for the IOUs; (4) the increase to the settlement staves off contentious issues surrounding the traditional REP as well as provides a fair allocation of power to the IOUs; and (5) the increase will help ensure an appropriate sharing of benefits of Federal power among the residential ratepayers in the Northwest.

After review of the comments, BPA found the arguments for increasing the IOU settlement amount by 100 aMW to be compelling. BPA determined that the conditions surrounding the proposed increase to the proposed Subscription settlement of the REP were expected to be met. Therefore, BPA increased the amount of total benefits for the proposed settlements of the REP with regional IOUs from 1800 aMW to 1900 aMW.

2. Allocation of Settlement Benefits Among IOUs

In the Power Subscription Strategy, BPA noted its intent to request comments from interested parties regarding the amounts of Subscription settlement benefits that should be provided to individual IOUs. BPA also noted that the Commissions indicated that they would collaborate on an allocation recommendation. After review of all comments, BPA would determine the appropriate amounts to be allocated to the individual IOUs.

BPA solicited the Commissions' views on the proposed allocation of settlement benefits. This was appropriate because the Commissions have traditionally been responsible for establishing retail electric rates for residential consumers of the regional IOUs, including the credit applied to those rates to reflect benefits of the REP as determined by BPA. The Commissions also have a statutory responsibility to the residential consumers of the IOUs in their particular state jurisdiction. Furthermore, because of these responsibilities, a joint recommendation by the Commissions would likely reflect a fair allocation of benefits among the residential consumers of the Northwest states and would enhance the likelihood of BPA delivering the benefits in a way that would work for each state and its consumers.

The Commissions collaborated and submitted a joint recommendation on the proposed allocation of the settlement benefits. They noted that their recommendation reflects many different considerations, including the amount of residential and small farm load eligible for the REP, the historical provision of REP benefits, the REP benefits received in the last five-year period ending June 30, 2001, rate impacts on qualifying customers, and the individual needs and objectives of each state. BPA reviewed the Commissions' recommendation and determined that this proposal was a reasonable approach upon which to take public comment.

Virtually all commenters supported the allocation recommended by the Commissions and proposed by BPA. The reasons for such support included: (1) it is appropriate for BPA to weigh heavily the Commissions' joint recommendation concerning the allocation of benefits; (2) the Commissions are the best arbiters of the settlement among the IOUs; and (3) the proposed allocation establishes access to a level of benefits that recognizes changed market conditions while at the same time addresses the needs and issues important to each of the four states. It is worthy of note that BPA's allocation has received support from diverse customer and interest groups: publicly owned utilities, IOUs, the Commissions, state agencies, and a city commission. BPA concluded that the following allocation amounts would be incorporated into the proposed settlement contracts with the individual IOUs that choose to settle the REP:

	Amount of Settlement (aMW) FY2002-2006	Amount of Settlement (aMW) FY2007-2011
Avista Corp. 1/	90	149
Idaho Power Company 1/	120	225
Montana Power Company	24	28
PacifiCorp (Total)	476	590
PacifiCorp (UP&L)	*140*	*140*
PacifiCorp (PP&L – WA) 1/	*83*	*109*
PacifiCorp (UP&L – OR) 1/	*253*	*341*
Portland General Electric	490	560
Puget Sound Energy (PSE)	700	648
Total	1900	2200

1/ BPA also concluded that the allocation of benefits among the states served by these multi-state utilities would be based on the forecasts of the respective state residential and small farm loads at the time the IOU signs its Settlement Agreement.

E. BPA's Section 5(b)/9(c) Policy

As BPA recognized that its existing long-term power sales contracts would soon expire, BPA proposed to establish a policy to guide the agency in making determinations of the net requirements of its utility customers in order to offer Federal power under new contracts. (For the most part, existing power sales contracts expire by October 1, 2001.) A net requirements policy is an important component to BPA's execution and implementation of new power sales contracts. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a contract to each requesting public body, cooperative, and investor-owned utility to meet each utility's regional firm load net of the resources used by the utility to serve its firm power consumer load. 16 U.S.C. § 839c(b)(1) (1994 & Supp. III 1997). In making this determination, BPA has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), and section 3(d) of the Regional Preference Act, 16 U.S.C. § 837b(d) (1994 & Supp. III 1997).

BPA provided two opportunities for public review and comment in developing its proposed policy. On May 6, 1999, BPA published its initial policy proposal, entitled "Opportunity for Public Comment Regarding Bonneville Power Administration's Subscription Power Sales to Customers and Customer's Sale of Firm Resources," 64 Fed. Reg. 24,376 (1999). BPA held two public meetings to discuss this policy. The first meeting was held on May 27, 1999, in Spokane, Washington. The second meeting was held on June 2, 1999, in Portland, Oregon. On June 3, 1999, the thirty-day comment period was extended by BPA through June 30, 1999.

After reviewing and considering the comments received on the initial policy proposal, particularly those that requested that BPA provide a second round of review and comment, BPA issued a revised policy proposal on October 28, 1999, entitled "Revised Draft Policy Proposal Regarding Subscription Power Sales to Customers and Customer's Sales of Firm Resources," 64 Fed. Reg. 58,039 (1999). BPA reviewed and considered the comments received on the revised policy. On May 24, 2000, BPA issued its final "Policy on Determining Net Requirements of Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act," also called BPA's "Section 5(b)/9(c) Policy." BPA also issued a Section 5(b)/9(c) Policy Record of Decision.

F. IOU Settlement Agreements

After completion of the Administrator's Supplemental ROD, BPA began the development of a prototype Residential Purchase and Sale Agreement (RPSA) and a prototype Settlement Agreement. On May 5, 2000, BPA sent a letter to all interested parties requesting comments on the proposed agreements. BPA's letter included a background document describing the two agreements. BPA also enclosed copies of the draft RPSA and Settlement Agreement. BPA's letter and attachment noted that BPA's Power Subscription Strategy proposed comprehensive settlements of the REP with participating regional IOUs and that IOUs would also have the option of entering into contracts to participate in the REP. The Power Subscription Strategy also noted that public agency customers were eligible to enter RPSAs under the REP.

BPA's letter noted that BPA had prepared a prototype RPSA to implement the REP and that this prototype would be used as the basis for contracting with all eligible parties to apply for benefits under the REP. BPA requested public comment on the following issues: (1) which entities are eligible utilities to request benefits under section 5(c) of the Northwest Power Act; (2) BPA's proposal to implement the in lieu provisions of section 5(c)(5) of the Northwest Power Act through wholesale market purchases; (3) any exceptions to the limitations of section 5(c)(6) that preclude the restriction of exchange sales under section 5(c) below the amounts of power acquired from, or on behalf of, the utility pursuant to section 5(c); and (4) any comments on the terms and conditions of the prototype RPSA agreement.

BPA's letter also described BPA's proposal for comprehensive settlement of the rights of regional IOUs eligible for benefits under the REP. BPA noted that it had prepared a prototype Settlement Agreement for implementing the Subscription Strategy. The prototype provided power sales pursuant to a contract offered under section 5(b) of the Northwest Power Act. The prototype also provided for the payment of monetary benefits. BPA requested public comment on all relevant issues, including the following issues: (1) any comments on the terms and conditions of the prototype Settlement Agreement; and (2) whether the total amount of benefits and the proposed terms and conditions for settling the rights of regional IOUs to request benefits under the REP were reasonable.

BPA's letter noted that BPA's Power Subscription Strategy proposed an allocation of benefits to the region's IOUs that included both physical and monetary components. It further noted that the Administrator's Supplemental ROD for the Power Subscription Strategy proposed to offer the IOUs the equivalent of 1900 aMW of Federal power for the FY 2002-2006 period. Of this amount, at least 1000 aMW would be provided in physical power deliveries. BPA requested that each IOU notify BPA by July 21, 2000, whether they wished to participate in BPA's REP. The IOUs were not required to make an election whether to accept a settlement offer or participate in the REP through an RPSA at that time. Based on each IOU's request to participate in the REP, BPA would prepare a settlement offer for their consideration prior to October 1, 2000. At the time each IOU requested to participate in the REP in July 2000, BPA's letter asked that each IOU identify (1) its preferred mix of physical deliveries and financial settlement; and (2) whether it would prefer a five-year or 10-year offer. BPA would only make a settlement offer including net requirements physical deliveries if the IOU could establish a net requirement for the amount of power requested.

BPA's letter requested public comment on two issues regarding the offer of physical power and financial benefits in settlement of REP rights: (1) whether BPA should require IOUs to take additional power if the combined requests of all the companies for physical deliveries are less than 1000 aMW; and (2) how BPA should limit physical deliveries to each IOU if the companies requested physical deliveries of more than 1000 aMW and such deliveries were more power than BPA was willing to offer.

Comments on all of the issues regarding the prototype agreements were to be submitted through close of business on Friday, June 9, 2000. BPA's letter noted that after receiving public comment on the proposed prototype agreements, BPA would prepare final draft prototypes based on the public comments. These draft prototypes will be published to allow IOUs to determine whether they wish to participate in the REP pursuant to an RPSA or through a settlement offer based on physical or monetary benefits. Once BPA received each IOU's request to participate in the REP, BPA would prepare a settlement offer and an RPSA for each IOU in accordance with the choices made. BPA prepared a ROD addressing the public comments on the proposed REP Settlement Agreements. A separate ROD was also issued which addressed the public comments on the proposed RPSA. BPA offered both an RPSA and a Settlement Agreement to each IOU.

On July 28, 2000, BPA sent a letter to interested parties regarding a request by Montana Power Company (MPC) to be offered a Settlement Agreement in which the power component would be made under section 5(c) of the Northwest Power Act instead of a sale of requirements power under section 5(b) of the Act. BPA's letter noted that on May 5, 2000, BPA asked for public comment on BPA's proposed contracts for implementing the REP, including a request for comments on a proposed IOU Settlement Agreement. The Settlement Agreement BPA offered for comment on May 5, 2000, contained benefits that were comprised of proposed power sales and monetary payments. The power sales proposed under the Settlement Agreement were sales under section 5(b) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997). However, as BPA stated in its Power Subscription Strategy, released on December 21, 1998, power sales in its proposal for settling the REP could be based either under section 5(b) or 5(c) of the Northwest Power Act. In the background document included with BPA's May 5, 2000, letter, BPA noted that it had not prepared a prototype Settlement Agreement based on a power sale under section 5(c) of the Northwest Power Act, but that it would consider such proposals if they were made.

In a letter dated July 27, 2000, MPC requested that BPA provide a settlement offer including firm power benefits under section 5(c) of the Northwest Power Act. BPA prepared a draft Settlement Agreement reflecting a section 5(c) power sale. The proposed settlement, attached to BPA's July 28, 2000, letter, was very similar to the proposed agreement that BPA issued for public comment with BPA's May 5, 2000, letter. Instead of providing an IOU Firm Power Block Sales Agreement (Block Sales Agreement) for a specified amount of firm power under section 5(b) of the Northwest Power Act, this proposed section 5(c) prototype agreement provided a specified amount of firm power under a Negotiated In Lieu Agreement.

On October 4, 2000, the BPA Administrator issued a decision document entitled "Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision," which concluded that it was appropriate to offer the REP Settlement Agreements to regional IOUs. The REP Settlement Agreements were then executed the same month.

G. BPA's 2002 Wholesale Power Rate Case

BPA's 2002 wholesale power rate case developed power rates for the five-year rate period commencing October 1, 2001, through September 30, 2006. BPA's 2002 Wholesale Power Rate Adjustment Proceeding was the forum for the pricing implementation of BPA's Power Subscription Strategy adopted December 21, 1998. The Subscription Strategy, as well as other agency processes, provided the policy context for BPA's section 7(i) hearings.

On August 13, 1999, BPA published its notice of 2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment. 64 Fed. Reg. 44318 (1999). BPA's 2002 wholesale power rate proceeding began with a prehearing conference on August 24, 1999. BPA's 2002 initial power rate proposal, filed on August 24, 1999, was supported by prefiled written testimony and studies sponsored by approximately 68 witnesses. Oral clarification on BPA's initial power rate proposal occurred from September 13-19, 1999. Direct testimony was filed by the parties on November 2, 1999. Clarification on the parties' direct testimony occurred from November 15-19, 1999. On December 17, 1999, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases. The parties filed their prehearing briefs one week later. Clarification on the litigants' rebuttal testimony occurred on January 4-5, 2000. Written discovery of BPA's and the parties' direct and rebuttal cases occurred throughout the hearing. BPA responded to 1,196 data requests concerning its initial rate proposal and its rebuttal testimony.

Cross-examination took place from January 24, 2000, through February 4, 2000. The parties submitted initial briefs on February 28, 2000. Oral argument before the Administrator was held on March 2, 2000. The Draft ROD was issued and distributed to parties on April 10, 2000. On April 24, 2000, the parties submitted briefs on exceptions in response to the Draft ROD. The Final ROD was signed by the Administrator on May 10, 2000.

On July 6, 2000, pursuant to section 7(a)(2) of the Northwest Power Act, BPA filed its proposed rate adjustments for its wholesale power rates with the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 839e(a)(2). On August 4, 2000, BPA filed a motion with FERC requesting a stay of review of the rate filing for 30 days. Thereafter, BPA reviewed events during the summer months which indicated that power markets on the West Coast had become more volatile than previously anticipated.

BPA concluded that, in light of the unprecedented price spikes during the summer months, BPA's cost-based rates for 2002-2006 would be far more attractive to prospective customers than market alternatives. As a result, preference customers could be expected to purchase significantly more power than originally anticipated. During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources, requiring BPA to purchase 1,745 aMW of system augmentation. BPA later expected loads would exceed the original rate case forecast, requiring BPA to purchase an additional 1,560 aMW of system augmentation. Total system augmentation purchases for the five-year rate period were forecasted to average 3,305 aMW. Moreover, the difficulty of forecasting the expense of serving the increased load obligations was magnified by the fact that prices were escalating in an extraordinarily volatile market.

The combination of an unanticipated increase in loads with higher and more uncertain market prices greatly diminished the probability that the rates proposed in the initial phase would fully recover generation function costs. Absent a change to the proposed rates, BPA's Treasury Payment Probability (TPP) was significantly reduced. By law, BPA's payments to Treasury are the lowest priority of revenue application, meaning that such payments are the first to be missed if reserves are insufficient to pay all bills on time. For this reason, BPA expresses its cost recovery goal in terms of probability of being able to make Treasury payments on time. A TPP that is too low reflects an unacceptable degree of financial risk for BPA and the Treasury.

The increased load obligations that BPA would be meeting through market purchases in an escalating and volatile market environment had decreased TPP to an unacceptable level. BPA also implemented the Fish and Wildlife Principles (Principles) in the 2002 rate proposal. Among other provisions, the Principles call for a TPP goal of 88 percent, and an acceptable range of 80 to 88 percent for the five-year, FY 2002-2006 rate period. The rates and risk mitigation tools were initially developed to achieve the TPP goal of 88 percent in full. After the rates were filed at FERC, increases and uncertainty surrounding augmentation purchase costs drove the TPP estimate to well below 70 percent.

To ensure that TPP fell within the acceptable range, in early August 2000, BPA began to explore options to solve its cost recovery problem. On August 1, 2000, BPA suspended the signing of any new power contracts with customers and initiated a separate public process to examine the problem and explore potential solutions. On August 3, 2000, BPA wrote a letter to rate case parties and other interested entities in the region, outlining two possible alternatives for dealing with the problem. The first alternative entailed modifying a five-year rate lock provision in BPA's power contracts to give BPA the ability to reset rates if necessary after September 30, 2003. The second alternative involved modifying the 2002 rate filing to address the problem. The letter requested written comment regarding the proposed alternative or any other ideas the parties had for addressing the problem.[1] In addition, BPA set August 9, 2000, for a technical discussion of the issues facing BPA and August 21, 2000, for a public meeting to discuss the range of options.

BPA received over 60 written comments in response to its August 3 letter. On August 31, 2000, after the public meeting, BPA wrote a second letter to rate case and other interested parties. After consideration of all the comments and BPA's own internal analysis, a decision was made to explore some specific rate adjustments to deal with the cost recovery problem, rather than proposing modifications to all the contracts. BPA concluded that it could maintain an acceptable TPP level by revising the CRAC contained in the proposed 2002 General Rate Schedule Provisions (GRSPs) and by making some corresponding changes to the Slice methodology.

BPA set aside the following weeks to engage the rate case parties in settlement discussions aimed at resolving the cost recovery problem in a mutually agreeable way. These discussions centered on four major issues presented by the option proposed by BPA:

1. How should the CRAC be redesigned to provide BPA with the necessary financial protection?
2. How should the Slice product be modified to insure that Slice customers pay an equitable share of BPA's augmentation costs?
3. What changes, if any, are necessary to the proposed settlement of the IOUs Residential Exchange benefits, as a consequence of the revision to the CRAC?
4. How would the proposed changes to the CRAC impact customers who had already signed contracts?

65 Fed. Reg. 75272, at 57274 (2000).

BPA notified FERC on September 4, 2000, of its decision to pursue modifications to the CRAC and requested that the stay be extended through April 30, 2001, so that settlement discussions could be continued and a limited section 7(i) proceeding could be conducted.

[1] BPA initially asked for all written comments by August 24, 2000, but during the August 21, 2000, meeting, BPA extended the time for customers to provide comments while settlement discussions occurred. In her October 6, 2000, letter to customers, the Administrator requested all comments be sent to BPA by October 16, 2000.

During the month of September 2000, BPA and rate case parties engaged in a series of meetings to discuss ways of resolving the four major issues described above. Despite this effort, the parties were unable to reach a consensus.

On October 6, 2000, BPA notified rate case parties that it intended to initiate a limited section 7(i) proceeding to revise the CRAC; make adjustments to the Slice methodology; adjust the forecasts used in the Residential Exchange Settlements; and address the Subscription contracts signed in the summer of 2000 in order to deal with the issues facing BPA. The Administrator set the close of business on October 16, 2000, as the date after which any *ex parte* communications with BPA would be prohibited.

On December 1, 2000, BPA published a Federal Register Notice of Proposed Amendments to 2002 Wholesale Power Rate Adjustment Proposal, 65 Fed. Reg. 75272 (2000). BPA's 2002 amended wholesale power rate proceeding began with a prehearing conference on December 12, 2000. At that prehearing conference, the Hearing Officer issued orders concerning procedural matters in this proceeding. BPA's Amended Proposal, filed on December 18, 2000, was supported by prefiled written testimony and studies sponsored by approximately 25 witnesses. On December 18, 2000, the Hearing Officer issued an order establishing the schedule for the rate proceeding. Oral clarification on BPA's Amended Proposal occurred on December 18 and 19, 2000. The schedule was revised on January 31, 2001, and March 2, 2001, to accommodate settlement discussions between BPA staff and rate case parties.

BPA's Amended Proposal rate case was a continuation of the WP-02 rate proceeding. It was being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. During the consideration of the Amended Proposal, however, BPA concluded that it was necessary to make additional changes to ensure BPA's cost recovery.

On January 9, 2001, BPA issued a notice of a workshop with customers to address a settlement proposal submitted by a group of BPA customers. That noticed settlement workshop took place on January 11, 2001, and was continued to January 19, 2001, and January 23, 2001. Noticed settlement workshops also took place on January 31, 2001, February 2, 2001, February 6, 2001, and February 13, 2001.

On January 31, 2001, BPA filed a request with the Hearing Officer to amend the procedural schedule, given that BPA staff and parties were in the process of noticed settlement discussions. On January 31, 2001, the Hearing Officer granted BPA's request.

As a result of these discussions, a partial stipulation and settlement was reached between BPA staff and the Joint Customer Group, which was comprised of Avista Corporation (Avista), Idaho Power Company (IPC), PacifiCorp, Portland General Electric (PGE), Puget Sound Energy, Inc., Seattle City Light, Market Access Coalition,[2] Northwest

[2] Market Access Coalition Group includes: Benton County Public Utility District (PUD), Franklin County PUD, Grays Harbor PUD, City of Richland Energy Service Department, and Klickitat County PUD.

Requirements Utilities,[3] Pacific Northwest Generating Cooperative,[4] Public Power Council,[5] Public Generating Pool,[6] Western Public Agencies Group,[7] Idaho Public Utilities Commission, Montana Public Service Commission, Public Utility Commission of Oregon, and Washington Utilities and Transportation Commission. The Partial Stipulation and Settlement Agreement became effective on February 15, 2001.

The settlement was incorporated into the BPA staff's Supplemental Proposal. On February 15, 2001, BPA staff filed the Supplemental Proposal. The Supplemental

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[3] Northwest Requirements Utilities includes: Benton County PUD, Benton Rural Electric Association, Central Lincoln PUD, Columbia Basin Electric Cooperative, Columbia Power Cooperative, Columbia REA, Columbia River PUD, Ferry County PUD No. 1, City of Forest Grove, Franklin County PUD, Harney Electric Cooperative, Hood River Electric Cooperative, City of Idaho Falls, Inland Power & Light, Klickitat County PUD, McMinnville Water & Light, Midstate Electric Cooperative, Nespelem Valley Electric Cooperative, Northern Wasco County PUD, Orcas Power & Light, Oregon Trail Electric Cooperative, City of Rupert, Skamania County PUD, Surprise Valley Electrification Corp., Tanner Electric Cooperative, United Electric Cooperative, Vera Water & Power, Wasco Electric Cooperative, and Wells Rural Electric

[4] Pacific Northwest Generating Cooperative includes: Blachly-Lane Electric Cooperative, Central Electric Cooperative, Inc., Clearwater Power Company, Consumers Power Inc., Coos-Curry Electric Cooperative, Inc., Douglas Electric Cooperative, Fall River Rural Electric Cooperative, Inc., Lane Electric Cooperative, Inc., Lost River Electric Cooperative, Northern Lights Inc., Okanogan County Electric Cooperative, Inc., Raft River Rural Electric Cooperative, Inc., Salmon River Electric Cooperative, Inc., Umatilla Electric Cooperative, and West Oregon Electric Cooperative, Inc.

[5] Public Power Council includes: City of Albion, Alder Mutual Light Co., Ashland, Bandon, Benton PUD, Benton REA, Big Bend, Blachly-Lane Electric, Blaine City Light, Bonners Ferry, Burley Municipal District, Cascade Locks, Central Electric Cooperative, City of Centrala, Chelan County PUD, Cheney, City of Chewelah, Clallam PUD, Clark Public Utilities, Clatskanie PUD, Clearwater Power, Columbia Basin Electric, Columbia Power, Columbia River PUD, Columbia REA, Consumers Power, Coos-Curry Electric, Town of Coulee Dam Light Department, Cowlitz PUD, City of Declo, Douglas Electric Cooperative, Douglas PUD, Drain Light & Power, East End Mutual, Eatonville, Ellensburg, Elmhurst, Emerald PUD, Eugene Water and Electric Board, Fall River, Farmers Electric Co., Ferry PUD, City of Fircrest, Flathead, Forest Grove, Franklin PUD, Glacier, Grant PUD, Grays Harbor PUD, Harney, Heyburn, Hood River, Idaho County, Idaho Falls, Inland, Kittitas PUD, Klickitat PUD, Kootenai, Lakeview, Lane, Lewis PUD, Lincoln Electric, Lost River, Lower Valley Energy, Mason PUD No. 1, Mason, PUD No. 3, McCleary Light & Power, McMinnville, Midstate Electric, Milton, Milton-Freewater, City of Mindoka, Mission Valley Power, Missoula, Modern Electric Water Co., Monmoth, Nespelem Valley Electric Cooperative, Northern Lights, Northern Wasco PUD, OHOP Mutual Light Co., Okanogan Electric, Okanogan PUD, Orcas Power & Light, Oregon Trail Electric Cooperative, Pacific PUD, Parkland, Pend Oreille PUD, Peninsula Light, City of Plummer, Port Angeles, Raft River, Ravalli, Richland, Riverside, Rupert, Salem Electric, Salmon River, Skamania PUD, Snohomish PUD, City of Soda Springs, South Side Electric, Springfield Utility Board, Town of Steilacoom, Sumas, Surprise Valley Electrification Cooperative, Tacoma Power, Tanner Electric, Tillamook PUD, Umatilla Electric, United Electric, Vera, Vigilante, Wasco Electric, Wells Rural, West Oregon, Wahkiakum PUD, and Whatcom PUD.

[6] The Public Generating Pool includes: Grant County PUD No. 2, Eugene Water & Electric Board, Seattle City Light, Tacoma City Light, Cowlitz County PUD, Chelan County PUD, Douglas County PUD, and Pend Oreille County PUD.

[7] Western Public Agencies Group includes: PUD No. 1 of Snohomish County, Elmhurst Mutual Power and Light Company, Ohop Mutual Light Company, City of Ellensburg, PUD No. 2 of Pacific County, PUD No. 1 of Clark County, PUD No. 1 of Grays Harbor County, Peninsula Light Company, Lakeview Light & Power Company, Parkland Light and Water Company, PUD No. 1 of Clallam County; PUD No. 1 of Lewis County; PUD No. 1 of Mason County, PUD No. 3 of Mason County, City of Cheney, Alder Mutual Light Company, City of Milton, Town of Steilacoom, Town of Eatonville, City of Fircrest, and PUD No. 1 of Kittitas County.

Proposal was supported by prefiled written testimony and a study that were sponsored by approximately 25 witnesses. There were three reasons BPA filed a Supplemental Proposal. First, BPA's forecast for starting rate period reserves had dropped very substantially since the forecast in its Amended Proposal. Second, market prices available for power during the first two years of the rate period were significantly higher than BPA had forecast in the Amended Proposal. Regardless, BPA would have prepared an update to the Amended Proposal to show the impact of these revised forecasts on BPA's proposed rates. The third reason was that, as a result of discussions with the rate case parties, BPA reached a Partial Settlement Agreement with many of those parties. Part of that agreement was that BPA would file a Supplemental Proposal reflecting the Partial Settlement Agreement.

Since BPA filed its Amended Proposal in December 2000, forecasts for run-off for the water year had declined substantially. Water Year forecasts in BPA's 2002 Final Power Rate Proposal (May Proposal) and Amended Proposal assumed average water for both this FY 2001 and for the next five years of the rate period – 102.4 million acre feet (MAF). By contrast, the current year could be the second lowest runoff year on record, with current runoff forecasted at under 60 MAF. These conditions would require BPA to purchase much more power this year than expected to meet loads, at extremely high prices, and to reduce the amount of surplus energy BPA can sell this year. As BPA described in its Amended Proposal, prices in the wholesale electricity market had been extremely volatile and high. BPA had seen these increased market prices during this year. In fact, during one week in January 2001 alone, BPA purchased over $50 million in power to meet load. This was putting tremendous pressure on BPA's end-of-year reserves. End-of-year reserves translate into starting rate period reserves. In BPA's May Proposal, starting reserves were estimated to be $842 million on an expected value basis. In BPA's Amended Proposal, starting reserves expected value estimates had increased to $929 million. Then, the expected value of BPA's starting reserves estimate dropped to $309 million. There was still a significant range of uncertainty surrounding this estimation of starting reserves. This was driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices.

Starting reserves were a key risk mitigation tool in BPA's Supplemental Proposal. A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools needed to be made.

Market prices during the rate period are higher in the first years of the rate period, ranging from $200/megawatthour (MWh) to $240/MWh for FY 2002, and then dropping during the last years of the rate period, to a range between $40/MWh and $60/MWh in FY 2006. This compares with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around $48/MWh, where expected prices for individual years did not vary by more than $5/MWh from the $48/MWh average.

Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market.

On March 2, 2001, BPA again filed a request with the Hearing Officer to amend the procedural schedule to allow parties additional time to file their direct cases. On March 2, 2001, the Hearing Officer granted a time extension setting March 7, 2001 as the date for parties' direct cases. On March 27, 2001, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases. Written discovery of BPA's and the parties' direct and rebuttal cases occurred throughout the hearing. BPA responded to approximately 350 data requests concerning its amended rate proposal and its supplemental proposal.

Cross-examination took place on April 12 and 13, 2001. The parties submitted initial briefs on April 24, 2001. Oral argument before the Administrator was held on May 2, 2001. The Draft Supplemental ROD was issued and distributed to parties on May 25, 2001. On June 5, 2001, parties submitted briefs on exceptions. For interested persons who do not wish to become parties to the formal evidentiary hearings, BPA's Procedures provide opportunities to participate in the ratemaking process by submitting oral and written comment. *See* section 1010.5 of BPA's Procedures. BPA took oral and written comments at a transcribed field hearing conducted on January 22, 2001, in Portland, Oregon. BPA received and considered 690 written comments submitted during the participant comment period, which officially ended on February 14, 2001. BPA also received many written comments after the end of the official comment period through the issuance of the Draft Supplemental ROD. After the issuance of the Draft Supplemental ROD, BPA received thousands of additional public comments. The transcribed field hearing and the comments from these rate case participants are part of the record upon which the Administrator based his decisions.

BPA's Supplemental Proposal dealt with cost recovery problems by amending certain risk mitigation tools contained in BPA's GRSPs, which apply to BPA's base rates. BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. The additional hearing phase addressed the problems created by increased purchase power costs created due to increased loads resulting from higher prices in a volatile market environment.

The Supplemental Proposal (like the Amended Proposal before it) contained the same risk mitigation tools as the May Proposal – Planned Net Revenues for Risk (PNRR), Fish Cost Contingency Fund (FCCF) credits, and starting reserves. (*See* May ROD, WP-02-A-02, at 7-2.) The FCCF credits and starting reserves were updated to reflect more current forecasts. The May Proposal included a single CRAC, while the Supplemental Proposal includes a three-component CRAC mechanism, designed to maintain the TPP level within the 80-88 percent TPP range called for in the Principles. Lefler, et al., WP-02-E-BPA-73, at 5-6. The three components are the Load-Based (LB) CRAC, the Financial-Based (FB) CRAC, and the Safety-Net (SN) CRAC, which are described as follows:

The LB CRAC is designed to cover the net cost of augmenting BPA's system to meet the additional 1,518 aMW of load placement by what is, in effect, a variable price mechanism. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been designed to be responsive to changes in the market price of power. BPA will establish a preliminary LB CRAC amount for each year of the rate period, FY 2002-2006. The amount will be based on the current forecast of forward market prices for each year, shaped, and the amount by which loads contracted for exceed BPA resources, less purchases for augmentation prior to August 1, 2000. Second, the preliminary LB CRAC amount will be adjusted for each six-month period of the rate period, beginning October 2001. Finally, about 90 days after the end of each six-month period, BPA will true-up the LB CRAC based on actual augmentation purchases during the period. Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-11 and 5-12. For purposes of calculating the LB CRAC, BPA will assume Conservation Augmentation costs are capitalized.

The FB CRAC is structured in substantially the same way as the CRAC in the May Proposal—it triggers when a forecast of Accumulated Net Revenues (ANR) falls below a threshold value for a particular year. It can generate additional cash in that year, with the amount limited to a pre-determined amount in all but the first year. The FB CRAC differs from the one proposed in May 2000, in two significant ways. First, the annual cap on new revenue collection for FY 2002 was removed: in FY 2002 the FB CRAC can collect whatever amount of additional revenues would have been needed to raise ending FY 2001 ANR to the reserves equivalent of the $300 million threshold value for that year. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same. Thresholds are set at the ANR equivalents of $300 million in reserves for FY 2001 and 2002, and $500 million for FY 2003-2005. Annual caps on revenue collection, after the first year, are $135 million for FY 2003, $150 million for FY 2004-2005, and $175 million for FY 2006. Second, the timing of the collection of the FB CRAC has changed. In the May Proposal, it was proposed that determination of whether the FB CRAC trigger is reached would be based on audited actual financial data available in January, and that collection would be made over a 12-month period beginning in April. By contrast, the Amended Proposal called for collecting the full amount in the four months between March and June. In this Supplemental Proposal, the FB CRAC reverts to the 12-month collection period. However, collection would begin in October following an initial determination made in August after the Third Quarter Review. *Id.* at 5-13.

The SN CRAC is a provision designed to raise rates if a payment to Treasury or other creditor has been missed, or there is a 50 percent probability that such a payment may be missed in the then-current year. Triggering of the SN CRAC starts an expedited section

7(i) proceeding, in which changes to the amount, duration, and timing parameters of FB CRAC can be made, taking into account conditions prevailing at the time. Because these changes cannot be known at this time, and because SN CRAC will not affect the calculation of the TPP, SN CRAC is not modeled in ToolKit. *Id.* at 5-13.

ISSUE

The issue presented is how BPA's Load-Based and Financial-Based Cost Recovery Adjustment Clauses (LB and FB CRACs) apply to the Residential Load (RL) and PF Exchange Subscription (PFXS) rate schedules where the power benefit portion of the Residential Exchange Program (REP) Settlement Agreements with investor-owned utilities (IOUs) is converted to cash upon termination of the Firm Power Block Sales Agreement under section 16 of that Agreement.

DISCUSSION

As noted previously, the REP settlements provide the IOUs with 900 aMW of financial benefits and 1,000 aMW of power benefits. The power provided to the IOUs by BPA under the settlements is sold at either the RL rate or the PFXS rate. The RL rate schedule has numerous features, including a reference to the application of BPA's CRACs. Section I of the rate schedule provides that "[s]ales under this schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process." In Section III.2, "Adjustments, Charges, and Special Rate Provisions," the rate schedule notes that the Cost Recovery Adjustment Clause, as found in Section II.F of the GRSPs, applies to the RL rate. Virtually identical language applies to the PFXS rate under the PF-02 rate schedule.

Section II.F of BPA's GRSPs, which addresses the application of the CRAC, was revised in BPA's 2002 Supplemental Wholesale Power Rate Proposal. Section II.F of the revised GRSPs notes that:

> There are three sets of conditions under which rate increases under [the] Cost Recovery Adjustment Clause[s] (CRAC) may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA's augmentation cost exceeds the amount forecast in the May Proposal. The second is the Financial-Based CRAC (FB CRAC), which triggers based on the generation function's forecasted level of accumulated net revenues. The third is the Safety-Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has or reasonably expects to miss a payment to the Treasury or another creditor.

See 2002 Final Supplemental GRSPs, WP-02-A-09, at 1. The current issue addresses only the LB CRAC and the FB CRAC, not the SN CRAC. Section II.F.1.a of the GRSPs describes the application of the LB CRAC. This section provides that:

> *The LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.* The LB CRAC will also apply to the Priority Firm Slice Rate, excluding revenues from the contractual true-up pursuant to the Slice Agreement, and payments pursuant to section X of these GRSPs.
>
> *The LB CRAC does not apply to* power sales under Pre-Subscription contracts to the extent prohibited by such contracts, *the 900 aMW of monetary benefits provided under the financial portion of the REP Settlement*, or to BPA's current contractual obligations for Seasonal Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product.

(Emphasis added). Section II.F.2 of the GRSPs describes the application of the FB CRAC. This section provides that:

> *The FB CRAC applies to power customers under these firm power rate schedules: PF* [Preference (excluding Slice), Exchange Program, and *Exchange Subscription*], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, *Residential Load (RL-02)*, New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). *The FB CRAC does not apply to* power sales under Pre-Subscription contracts to the extent prohibited by such contracts, purchases under the PF Slice Rate, *the 900 aMW of financial benefits provided under the financial portion of any REP Settlement* or for BPA's contractual obligations for Seasonal and Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product. *The FB CRAC does apply to the 1,000 aMW power sale portion of the REP Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.*

(Emphasis added). The GRSPs thus note that "[t]he LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, *including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.*" (Emphasis added). The GRSPs also note that "[t]he FB CRAC does apply to the 1,000 aMW power portion of the REP settlement, *including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.*" (Emphasis added). While this language clearly provides that the LB and FB CRACs apply to the 1,000 aMW power sale portion of the REP Settlement, the language is ambiguous regarding the application of the CRACs where power benefits are converted to cash. The language states "*including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.*" This language creates an ambiguity because the language does not make clear whether the LB and FB CRACs apply to conversions from power sales to cash payments *only* where such conversions are made pursuant to Section 5(b) of the Residential Exchange Settlement or whether the reference to Section 5(b) is a non-exclusive *example* of where there are conversions from power sales to cash payments. Because of this ambiguity, BPA must interpret its rates to determine the intended operation of the GRSPs. As a general rule, ratemaking is rulemaking and an agency's interpretation of its own rules is entitled to deference from the courts. *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 512; 114 S.Ct. 2381, 2386 (1994); *Providence Hosp. of Toppenish v. Shalala*, 52 F.3d 213, 216 (9th Cir. 1995).

A close review of the GRSPs helps to clarify the intent of the LB and FB CRAC provisions. The LB CRAC provisions state that "[t]he LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement . . ." Also, the LB CRAC provisions state that "[t]he LB CRAC does not apply to . . . the 900 aMW of monetary benefits provided under the financial portion of the REP Settlement . . ." Similar language is found in the provisions of the FB CRAC. These provisions state that "[t]he FB CRAC does not apply to . . . the 900 aMW of financial benefits provided under the financial portion of any REP Settlement . . . The FB CRAC does apply to the 1,000 aMW power sale portion of the REP Settlement . . ." These statements show the amounts of the IOU settlement benefits that were intended to be affected by the CRACs. One thousand aMW of benefits were intended to be subject to the CRACs and 900 aMW of benefits were not intended to be subject to the CRACs. This means that the CRACs should apply to the 1,000 aMW of power benefits, whether such benefits are provided as power or not.

BPA's staff witnesses Doubleday, Keep, Kitchen and Petty, who sponsored testimony regarding the application of the CRACs to the RL and PFXS rates, used the following logic for applying the LB and FB CRACs to the RL and PFXS rates for REP settlement benefits that are converted from power to monetary benefits. In its rate cases, BPA forecasts the costs associated with its obligation to serve customer load and provide customer benefits. Some of the cost forecasts are straightforward calculations of costs that are well-established in the rate case and have little or no variability between the actual costs and those that were forecasted. On the other hand, the forecast of the cost to serve BPA's load obligations involves more volatile parameters such as load variability and market price volatility. There may be wide differences between the actual costs associated with serving load and the costs that were forecasted. BPA has ratemaking tools to help mitigate this cost uncertainty. These tools include Planned Net Revenues for Risk (PNRR) from BPA's May 2000 rate proposal and the three CRACs in BPA's June 2001 Final Supplemental rate proposal. The costs associated with these risk mitigation tools are allocated to firm customer loads.

The IOUs' REP Settlements for the rate period include 900 aMW of fixed monetary benefits as well as 1000 aMW of power benefits. The fixed monetary benefits were calculated in the rate case. The actual cost of these benefits will be the same as the costs forecasted in the rate case. Because of this, PNRR costs were *not* allocated to the 900 aMW of monetary benefits in BPA's May 2000 rate proposal. BPA applied the CRAC in the May proposal to the rates for monetary benefits as well as financial benefits. BPA felt all sales including the rate used to calculate the monetary benefits should share in mitigating BPA's cost uncertainty. BPA reopened its rate case in August 2000, due to a recognition that BPA had underestimated loads that would be placed on BPA and due to significant increases in wholesale rate volatility. Because the monetary benefits were fixed, these benefits were deemed exempt from the LB CRAC and the FB CRAC in BPA's June 2001 Final Supplemental rate proposal. The monetary benefits, however, were subject to the SN CRAC, which mitigates BPA's cost uncertainty when BPA's Treasury payment is threatened.

The 1000 aMW of power benefits are included in BPA's firm load service obligations along with the loads of the DSIs and public agencies. BPA purchased system augmentation power in the market to serve its load obligations, including the 1000 aMW of IOU load. These market purchases exposed BPA to market price risk, that is, the actual market prices that BPA will pay for actual purchases may be different than BPA's forecast of market prices made during the rate case. Therefore, in the May 2000 rate proposal, the cost of PNRR was allocated to BPA's firm loads, including the 1000 aMW of IOU power benefits. Likewise, BPA's firm loads, including the 1000 aMW of IOU power benefits, are subject to the LB CRAC and the FB CRAC in BPA's June 2001 Final Supplemental rate proposal.

Conversion of a portion or all of the 1000 aMW of IOU power benefits to monetary benefits does not change the applicability of the CRACs to these benefits. Now that BPA's firm power rates have been calculated, the same type of market price risk is present if a power benefit to monetary benefit conversion is chosen by the IOUs. The LB CRAC is designed to cover the cost of system augmentation in excess of the system augmentation costs assumed in BPA's May 2000 rate proposal. In the event that an IOU conversion leaves BPA in a long position, with additional firm power to sell in the market, the market price risk is still present. For example, BPA could have purchased system augmentation at a higher rate than it is now able to command in the market when it tries to resell the power. Therefore, it is appropriate that the LB and FB CRACs apply to monetary benefits that were derived from the 1,000 aMW of settlement power where there is a conversion from power benefits to monetary benefits.

The foregoing logic is confirmed in BPA's rate case testimony. In BPA's direct policy testimony in BPA's 2002 Amended Wholesale Power Rate Proposal, BPA's witnesses noted:

> Q. Are there any proposed changes to the IOU Settlement Package?
>
> A. Yes. BPA's May Proposal applied the CRAC to BPA rates used to calculate the financial element of the IOU Settlement. Now, BPA is proposing that neither the LB CRAC nor the FB CRAC apply to the financial element of the IOU Settlement.

> Q. Why is BPA proposing this change?
>
> A. Exempting the rates used to calculate the financial element of the IOU settlement is the best way to address recent changes in market price volatility as it relates to BPA's commitment to residential and small farm consumers of investor-owned utilities. The financial benefit amount is calculated for each IOU by multiplying an amount of power times a price that is the difference between the RL rate and a fixed price established in the rate case. BPA believes that fixing this settlement payment provides an appropriate degree of certainty with respect to the value of the total settlement package, and should not change once BPA's rates have been approved. In addition, BPA intended to establish a forecast of market prices in its rate case that was fixed for the rate period. See Power Subscription Strategy, at 17. Use of a forecast was designed to protect BPA from the financial risk of actual market prices. See Power Subscription Strategy ROD, at 59.

Burns, *et al.*, WP-02-E-BPA-62. Separate BPA staff direct testimony stated:

> Q. Does BPA's Amended Proposal contain any other elements that would affect the benefits provided under the REP Settlements?
>
> A. Yes. As noted above, in the policy testimony of Burns, et al., WP-02-E-BPA-62, BPA proposes that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits under the REP Settlements, should be exempt from the proposed CRACs. The Load-Based CRAC is designed to recover the cost of serving load not forecasted in the May Proposal. The Financial-Based CRAC is designed to recover higher than expected costs, including increased market price purchases of power. BPA chose to protect the monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed CRACs instead of changing the $34/MWh forecast of 5-year forward flat block purchases. Since the amount of the monetary portion is fixed, it is reasonable to exclude the load served by the monetary benefits from the possible rate volatility introduced by application of the proposed CRACs. BPA's proposal provides a greater amount of certainty to the monetary benefit calculation.

Doubleday, *et al.*, WP-02-E-BPA-65. In BPA staff's direct testimony in BPA's 2002 Supplemental Wholesale Power Rate Proposal, BPA's witnesses stated:

> As noted above and as originally proposed in BPA's Amended Proposal in the policy testimony of Burns, *et al.*, WP-02-E-BPA-62, BPA proposes that the RL and PF Exchange Subscription rates, *only when used for the calculation of monetary benefits for the 900 aMW designated as monetary*

benefits in the REP Settlements, should be exempt from the proposed Load-Based and Financial-Based CRACs. *REP Settlement Power (1,000 aMW) that is converted into monetary benefits under the REP Settlement, however, shall use the RL or PF Exchange Subscription rate that applied to such power sales, i.e., the rate subject to the Load-Based CRAC and Financial-Based CRAC, in the calculation of such new monetary benefits.*

Doubleday, *et al.*, WP-02-E-BPA-74, at 8. (Emphasis added). This language unequivocally supports an application of the two CRACs to any conversions from power to monetary benefits. It states that power that is converted into monetary benefits *shall* use the rate that applied to the power sales, that is, *the rate subject to the Load-Based CRAC and Financial-Based CRAC,* in the calculation of such new monetary benefits. Also, during BPA's supplemental proposal rate hearing, all parties had the opportunity to address this issue. No party's direct testimony stated a rationale for not applying the LB and FB CRACs to the RL and PFXS rates where settlement benefits are converted from power to monetary benefits. The Joint Customer Group (JCG) redlined a copy of BPA's GRSPs and proposed deleting the language noted below, but this proposal was opposed by BPA staff and eventually rejected by the Administrator. In BPA staff's supplemental rebuttal testimony, staff stated:

> Q. Does BPA propose any changes to Section F(1)(a) of Attachment B?
>
> A. Yes. BPA proposes that one deletion proposed by the JCG in Attachment B on page 3 be retained rather than being deleted. The proposed deletion reads as follows: "The LB CRAC does apply to the 1,000 average megawatt (aMW) of power deliveries made under the power sale portion of the Residential Exchange Program (REP) Settlement, including where such power sales are converted to cash payments calculated pursuant to Section 5(b) of the REP Settlement Agreement."
>
> Q. What is BPA's rationale for not deleting this sentence?
>
> A. BPA believes that this is an important part of the complete statement about what the LB CRAC does and does not apply to [w]hat was reached as part of the Partial Settlement.

Lefler, *et al.*, W-02-E-BPA-77. The Administrator recognized BPA staff's position in the Final 2002 Supplemental Rate Proposal ROD at 5-5, which states:

> In its 2002 Supplemental Power Rate Proposal (Supplemental Proposal) direct testimony, BPA staff built upon their Amended Proposal. BPA staff noted that BPA had made a policy decision to adjust its forward flat block forecast from \$34.1/MWh to \$38/MWh. Doubleday, *et al.*, WP-02-E-BPA-74. This issue is addressed in the policy testimony of Burns and Berwager, WP-02-E-BPA-70. This adjustment was made for a number of reasons. Doubleday, *et al.*, WP-02-E-BPA-74. In summary, BPA staff recently conducted settlement discussions with all interested

> parties in BPA's WP-02 rate case. *Id.*, citing Burns and Berwager, WP-02-E-BPA-70. A large number of those parties proposed a partial settlement of many rate case issues. *Id.* One element of that proposal was that the forecast used to calculate the financial benefits under the REP Settlements should be \$38/MWh. *Id.* When viewed in the context of the Partial Stipulation and Settlement Agreement, BPA staff elected to make this adjustment, also noting that prices had increased since the time of BPA's Amended Proposal. *Id.* While BPA staff did not expect current prices to continue for the five-year period of the forward flat block forecast, BPA staff believed, viewed in the context of the total settlement proposal, that current high market prices lasting through the first 6 to 18 months of the forecast period justified an increase in the forecast price to \$38/MWh. *Id.*
>
> In addition to the issue of the rate case market price forecast, there is another issue that affects prospective REP Settlement benefits. As originally proposed in BPA's Amended Proposal in the policy testimony of Burns and Berwager, WP-02-E-BPA-62, BPA staff proposed that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits for the 900 aMW designated as monetary benefits in the REP Settlements, should be exempt from the proposed Load-Based (LB) and Financial-Based (FB) CRACs. *Id.* BPA staff argued that REP Settlement Power (1,000 aMW) that is converted into monetary benefits under the REP Settlement, however, should be subject to the LB CRAC and FB CRAC, in the calculation of such new monetary benefits. *Id.* The LB CRAC is designed to recover the cost of serving load not forecasted in the May Proposal. *Id.* The FB CRAC is designed to recover higher than expected costs, including increased market price purchases of power. *Id.* BPA chose to protect the 900 aMW designated as monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed LB and FB CRACs instead of changing the forecast of five-year forward flat block purchases. *Id.* Since the amount of the monetary portion is fixed, it was reasonable to exclude the load served by the monetary benefits from the possible rate volatility introduced by application of the proposed LB and FB CRACs. *Id.* BPA staff's proposal provides a greater amount of certainty to the monetary benefit calculation. *Id.*

2002 Supplemental Wholesale Power Rate Proposal ROD at 5-5.

The REP Settlement Agreements provide nothing contrary to the foregoing logic. It is helpful, however, to review the Agreement in order to understand the context of this issue. As noted above, the GRSPs note that "[t]he LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, including where power sales are converted to cash payments calculated *pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.*"

Similar language applies to the FB CRAC. Section 5(b) of the Residential Exchange Settlement Agreement provides, in pertinent part:

> 5. CASH PAYMENTS IF FIRM POWER NOT DELIVERED
>
> . . .
>
> (b) Determination of Cash Payment Amounts
>
> (1) Default Payment Option
> Cash payments pursuant to this section shall be made monthly according to the following formula:
>
> *FBNDP = (MIDC – WC – RL) x MWH*
>
> Where:
>
> FBNDP = Monthly Cash Payment Amount for Firm Power in MWh not delivered under sections 5(a)(1) through 5(a)(7) above.
>
> MIDC = The average price for the month of the Dow Jones daily firm On-Peak index price at the Mid-C for HLH, and the Dow Jones daily firm Off-Peak index price at the Mid-C for LLH based on volume weighted amount not delivered to Avista under Exhibit A. If, in the future, the Mid-C index is no longer available, or does not accurately reflect the value of daily firm energy, then it will be replaced with another prevailing index (or indices) that best represents the market price for firm power traded in eastern Washington.
>
> WC = Wheeling Charge from Federal system generators to the Mid-C point of delivery based on the posted Point-to-Point tariff of BPA's transmission business or its successor over unconstrained paths plus any mandatory posted ancillary service charges and transmission losses for scheduled power under such tariff. If, in the future, the Point-to-Point tariff is no longer available, or does not accurately reflect the cost of wheeling power from Federal system generators to the Mid-C point of delivery, then it will be replaced with a tariff that best represents the cost of wheeling fixed amounts of power between known points over unconstrained transmission paths.
>
> RL = The monthly RL rate calculated at 100 percent load factor for HLH and LLH periods.
>
> MWH = Monthly amount of power that cannot be delivered, expressed in megawatthours for HLH and LLH periods.

Section 5 of the settlement is entitled "Cash Payments If Firm Power Not Delivered." Section 5(a) of the settlement, which immediately precedes Section 5(b), defines the conditions when firm power is not delivered. These conditions include (1) where the amount of firm power exceeds the utility's net requirement, (2) where power has been assigned by the utility to a qualified entity, (3) where there is a restriction of power deliveries due to insufficiency, (4) where there is a termination or decrement for export of a regional resource, (5) where firm power is not delivered due to a monthly purchase deficiency, (6) where the utility terminates the Block Power Sales Agreement pursuant to section 16 of such agreement, and (7) where the Block Power Sales Agreement is held invalid. Section 5(a)(6) is the condition relevant to the current issue. Section 5(a)(6) provides:

> If [the utility] terminates the Firm Power Block Sales Agreement pursuant to section 16 of such agreement and section 4(c)(2)(C) applies, then section 4(b)(1)(B) of this Agreement shall not apply and the amounts of Firm Power not delivered during any month from the Effective Date of such termination through September 30, 2006, shall be converted to cash payments as provided in section 5(b) below.

Section 16 of the Firm Power Block Sales Agreement provides:

> TERMINATION.
> [Utility] may terminate this Agreement through a written notice up to 30 days after FERC grants interim approval for BPA's wholesale power rates that are effective October 1, 2001. In addition, [the utility] shall have the right to terminate this Agreement if all of the following conditions have been satisfied: [(1) any WP-02 rates are remanded to BPA by FERC or the Ninth Circuit Court of Appeals; (2) as a result of remand, BPA publishes a subsequent ROD resulting in the utility being subject to a higher average effective power rate for the period; and (3) the utility has provided written notice to BPA of its intent to terminate the Agreement within 30 days of publication of the subsequent final ROD].

However, section 4 of the settlement also addresses termination of the Firm Power Block Sales Agreement. Section 4(b) of the settlement provides:

> 4. SETTLEMENT BENEFITS
>
> . . .
>
> (b) Firm Power Sale Portion of Total Benefits
>
> (1) October 1, 2001, through September 30, 2006
>
> . . .

(B) If [the utility] terminates the Firm Power Block Power Sales Agreement pursuant to section 16 of such agreement, BPA shall convert the Firm Power sale to Monetary Benefits and provide Monetary Benefits in the amount of the Firm Power sale, pursuant to section 4(c) below (except as provided in section 5(a)(6) below), from the effective date of such termination through September 30, 2011.

Section 4(c) of the settlement provides, in pertinent part:

(c) Monetary Benefit Portion of Total Benefits

. . .

(2) Determination of Monetary Benefit Monthly Payment Amounts

(A) October 1, 2001, through September 30, 2006
The Monetary Benefit monthly payment amounts shall be determined in accordance with the following formula:

$$MP = \frac{(FBPF - RL) \times MB \times 8{,}760 \text{ hours } (8{,}784 \text{ hours in leap years})}{12 \text{ months}}$$

Where:

MP = Monthly Payment Amount

FBPF = Forward Flat-Block Price Forecast established in the same BPA power rate case as that which established the RL Rate during the period beginning October 1, 2001, through September 30, 2006.

RL = The RL Rate calculated at 100 percent annual load factor.

MB = Monetary Benefit amount in annual aMW.

In summary, where an IOU exercises its right to terminate the Firm Power Block Sales Agreement pursuant to section 16 of such agreement, that is, by written notice within 30 days of FERC granting interim approval of BPA's 2002 wholesale power rates, BPA converts the firm power sale to monetary benefits and provides monetary benefits in the amount of the firm power sale. It is important to note that this language was placed in the settlement and exhibits to address the possibility that, at the end of the rate case, BPA would adopt, and FERC would grant interim approval to, an RL rate that was higher than the PF Preference rate. If this occurred, the IOUs would not be satisfied with paying a rate higher than BPA's preference customers. This does not apply to the CRACs, of course, because the CRACs apply equally to the preference customers' purchases of PF power and the IOUs' purchases of the 1,000 aMW of RL power, including where such power was converted to cash payments. The basic manner in which the monetary benefits are calculated is by subtracting the RL rate from the Forward Flat-Block Price Forecast established in the same BPA power rate case as that which established the RL rate. This is multiplied by the amount of power the IOU would have purchased. The settlement refers only to the RL or PFXS rates. The RL and PFXS rates, discussed earlier, contain all of the features in the respective rate schedules. These features include the LB and FB CRACs.

Based upon the foregoing review, BPA staff's intent, which was adopted by the Administrator in BPA's 2002 Final Supplemental Wholesale Power Rate Proposal Record of Decision, was that the LB and FB CRACs would apply to the RL and PFXS rates when an IOU converted its power settlement benefits to monetary benefits.

CONCLUSION

I have reviewed and evaluated the record compiled by BPA on the foregoing issues regarding the application of the LB and FB CRACs to BPA's RL and PFXS rates. Based upon the record, the analysis expressed herein, and all requirements of law, I hereby conclude that BPA's 2002 GRSPs apply the LB and FB CRACs to BPA's RL and PFXS rates where an IOU chooses to terminate its Firm Power Block Sales Agreement after giving notice to BPA within 30 days of FERC granting interim approval to BPA's 2002 wholesale power rates, and the IOU's power benefits are converted to monetary benefits. This interpretation and implementation is consistent with the environmental analysis conducted for BPA's 1998 Power Subscription Strategy, BPA's Power Subscription Strategy NEPA ROD, BPA's Business Plan EIS and BPA's Business Plan ROD.

Issued at Portland, Oregon, this 28th day of September, 2001.

Stephen J. Wright

Acting Administrator and Chief Executive Officer