LITIGATION SETTLEMENT
INCLUDING SLICE SETTLEMENT AGREEMENTS AND INVESTOR-OWNED UTILITIES' AMENDED RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENTS

ADMINISTRATOR'S RECORD OF DECISION

Bonneville Power Administration
U.S. Department of Energy

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INTRODUCTION

This Record of Decision (ROD) addresses the development of a broad litigation settlement agreement between the Bonneville Power Administration (BPA) and parties to numerous petitions for review currently pending before the United States Court of Appeals for the Ninth Circuit. The settlement includes petitions filed by Portland General Electric Company (PGE), No. 01-70003; PacifiCorp, No. 01-70005; the Public Power Council, No. 01-70010; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70012; Puget Sound Energy, Inc., (Puget) No. 01-70041; and Atofina Chemicals, Inc., Columbia Falls Aluminum Co., Goldendale Aluminum Co., Kaiser Aluminum & Chemical Corporation, and Northwest Aluminum Co., No. 01-70042; challenging BPA's Residential Exchange Program (REP) Settlement Agreements with its regional investor-owned utility (IOU) customers. The settlement also includes petitions filed by Portland General Electric Company, No. 01-70002; PacifiCorp, No. 01-70008; the Public Power Council, No. 01-70009; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70014; Avista Corporation, No. 01-70020; Puget Sound Energy, Inc., No. 01-70041; and Northwest Aluminum Co., *et al*., No. 01-70060; challenging BPA's proposed Residential Purchase and Sale Agreements. The settlement also includes a petition filed by Puget Sound Energy, No. 01-70202, challenging BPA's Slice contracts with its preference customers. Finally, the settlement includes petitions filed by Pacific Northwest Generating Company (PNGC), Blachly-Lane County Cooperative Electric Association, Central Electric Cooperative, Inc., Consumers Power, Inc., Coos-Curry Electric Cooperative, Inc., Douglas Electric Cooperative, Lane Electric Cooperative, Lost River Rural Electric Cooperative, Northern Lights, Inc., Oregon Trail Electric Consumers' Cooperative, Raft River Rural Electric Cooperative, and Umatilla Electric Cooperative Association, No. 00-70948; and Puget Sound Energy, No. 00-70949, challenging BPA's Supplemental Subscription Strategy.

This ROD addresses the development of amendments to the following regional IOUs' REP Settlement Agreements with BPA: Avista Corporation, Contract Nos. 00PB-12157, 00PB-12163, and 03PB-11265; Northwestern Corporation, Contract Nos. 00PB-12160, 00PB-12165, and 03PB-11262; PacifiCorp, Contract Nos. 01PB-12229, 01PB-12230, 01PB-10854, 02PB-11157, and 03PB-11262; Portland General Electric, Contract Nos. 00PB-12161, 00PB-12167, and 03PB-11267; Puget Sound Energy, Inc., Contract Nos. 01PB-10885, 01PB-10886, 02PB-11156, and 03PB-11251; and Idaho Power Company, Contract Nos. 00PB-12158, 00PB-12164, and 03PB-11268. These agreements provide benefits to the residential and small farm consumers of the IOUs through a settlement of their participation in the Residential Exchange Program for the period from July 1, 2001, through September 30, 2011. 16 U.S.C. § 839c(c). The amendments addressed in this ROD provide for the deferral of a total of $225 million in benefits into the FY 2007-11 period, in addition to the $55 million of benefits previously deferred to that period. The amendments also revise a component in the formula for calculating monetary benefits under the REP Settlement Agreements. The amendments, in effect, provide for the continuation of the Reduction of Risk Discount through September 30, 2006, provide the basis for a substantial reduction in BPA's revenue requirement, and thereby BPA's wholesale power rates. This reduction would occur at a time of economic difficulty for the Pacific Northwest region.

This ROD also addresses the development of Slice Settlement Agreements between BPA and its Slice Customers. These agreements allow the Slice Customers to receive the benefits and assume the repayment obligation of the deferrals implemented in this settlement in a manner comparable (in timing and proportion) to BPA's non-Slice customers, and in a manner that does not change the Block/Slice Agreement, the Slice Rate Methodology, or the Slice Rate.

In order to fully understand the litigation settlement, proposed amendments, and Slice Settlement Agreements, it is helpful to understand BPA's initial development of the REP Settlements, and subsequent proceedings and events. 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 to 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 1970s, forecasts 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) in 1980. 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 continuing 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 residential and small farm customers of 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 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 REP has traditionally been implemented through Residential Purchase and Sale Agreements (RPSAs), the initial versions of which were executed in 1981. Between 1981 and 2001, Residential Exchange Termination Agreements were negotiated with all of the previously active exchanging utilities except Montana Power Company (MPC). MPC continued in "deemer" status through the expiration of its RPSA. 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 RPSA. BPA and some or all of the IOUs may have different legal interpretations with regard to the issue of deemer balances. Regional utilities were 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 time assuring the region of an adequate, efficient, economical and reliable power system.

Id. In 1996, the Steering Committee held 30 day-long 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 on the Committee's draft report throughout the region. *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 was at that time in the midst of significant restructuring. *Id*. This restructuring was 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 was at that time moving the industry away from the regulated monopoly structure of the past 75 years. *Id*. Today the region is still 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*.

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 was 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 was 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 decision-making. With the changing marketplace for electric power, there was 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 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 Slice proposal was evaluated by the Subscription Work Group, 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 addressed 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 sought 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 was considered fundamental to BPA's overall business purpose to provide public benefits to the Northwest through commercially successful businesses.

The Subscription Strategy was 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 described BPA proposals on a number of issues. These included the availability of Federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers could 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. 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.

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 of 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 accordance with the provisions of 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, under the proposed settlement the 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 the then-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, but was then amended and supplemented by BPA and filed with FERC on June 20, 2001. *See* Section H below. 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 commented on this increase. Parties supporting the increase cited 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," s*ee* 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 reflected 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. BPA's allocation 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, the then-existing power sales contracts expired 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) which regard the use and sale of power from customers' firm resources.

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 REP 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 REP 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, 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 would 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 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 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. Legal Challenges To REP Settlement Agreements

As noted above, on October 4, 2000, BPA issued a ROD regarding REP Settlement Agreements with BPA's IOU customers. All of BPA's regional IOU customers executed the Agreements. On January 2, 2001, Portland General Electric Company (PGE) filed a petition for review in the United States Court of Appeals for the Ninth Circuit, No. 01-70003, challenging the proposed Agreements. Additional petitions for review were filed by PacifiCorp, No. 01-70005; the Public Power Council, No. 01-70010; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70012; Puget Sound Energy, Inc., No. 01-70041; and Atofina Chemicals, Inc., Columbia Falls Aluminum Co., Goldendale Aluminum Co., Kaiser Aluminum & Chemical Corporation, and Northwest Aluminum Co., No. 01-70042.

On October 4, 2000, BPA issued a ROD regarding BPA's proposed Residential Purchase and Sale Agreements (RPSAs) with BPA's regional utility customers. In contrast to the REP Settlement Agreements, no utilities executed the RPSA, with all IOUs having executed the REP Settlement Agreements instead. On January 2, 2001, PGE filed a petition for review, No. 01-70002, challenging the proposed RPSAs. Additional petitions for review were filed by PacifiCorp, No. 01-70008; the Public Power Council, No. 01-70009; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70014; Avista Corporation, No. 01-70020; Puget Sound Energy, Inc., No. 01-70041; and Northwest Aluminum Co., *et al*., No. 01-70060.

While BPA's DSI customers filed petitions for review challenging the REP Settlement Agreements and the RPSAs, such petitions were conditional. The DSIs previously signed what is commonly referred to as the Compromise Approach. In their executed Compromise Approach contracts with BPA, the DSIs agreed as follows:

> If the Compromise Approach is substantially sustained in BPA's Rate Case Final Record of Decision, and [the DSI] desires to purchase power from BPA at the resulting rate, a condition of such sale is that the [the DSI] will not file a lawsuit challenging the sale of power under the Subscription Strategy to serve the residential and small farm loads of the Investor-Owned Utilities, or the rates for such sales, for the FY2002-2006 period, unless a party representing the interests of the residential and small farm customers of the investor-owned utilities files a lawsuit challenging the power sales or rates for service to the DSIs.

The DSIs reiterated their commitment not to challenge the IOUs' Subscription benefits in Section 16(j)(1) of their Subscription Block Power Sales Agreements with BPA. Section 16(j)(1) provides:

> **(j) Compromise Approach Covenant**
> [DSI Company] agrees that BPA substantially sustained the Compromise Approach in the Rate Case Final Record of Decision (ROD) issued by BPA on May 15, 2000. As a consequence [DSI Company] agrees:
>
> (1) [DSI Company] will not file suit in any court challenging the sale of power by BPA to any Pacific Northwest investor-owned utility (IOU) to serve the residential and small farm loads of the IOU, or the rate for such sales, for the Fiscal Year (FY) 2002-2006 period, unless such suit is filed: (A) on the 90^{th} day following the date of the final action being challenged; and (B) in response to a suit filed or reasonably expected to be filed by the IOUs or an IOU representative, challenging power sales or rates for service to the DSIs.
>
> . . .
>
> (3) [DSI Company] agrees that its failure to comply with any part of this provision will constitute a breach of this Agreement, and that BPA may terminate this Agreement in such case.

In their cover letter serving the joint petitions for review challenging the REP Settlement Agreements and the RPSAs, the DSIs confirmed that their joint petitions for review were filed on a conditional basis. The petitions were conditionally filed because, at the time by which petitions to review the IOU REP Settlement Agreements had to be filed, the DSIs could not know whether the IOUs would file lawsuits challenging the DSI power sales or rates. The DSIs' letter stated:

> My clients do not intend to pursue these Petitions if the IOUs do not actually file suit to challenge BPA's power sales or rates for service to the DSIs. Therefore, once the Petitions have been docketed at the Ninth Circuit, we will consult with your General Counsel's office to have the cases stayed until 90 days after the final decision on the WP-02 rates (i.e. 90 days after FERC approval). If, contrary to our current expectation, the IOUs do not file suit to challenge BPA's power sales or rates for service to DSIs, then we will seek dismissal of the Petitions.

DSI Letter to Paul Norman, December 29, 2000. The IOUs have not filed any lawsuits challenging power sales to the DSIs or the rates for such power sales. In fact, the IOUs have filed a joint petition for review of BPA's WP-02 rates at the Ninth Circuit that expressly waives and releases all challenges to DSI service or rates for service for the FY 2002-2006 period. Moreover, the litigation settlement contains a covenant by each IOU that "releases any and all claims it may have to challenge BPA power sales (or rates) for service to [DSIs] for the FY 2002-2006 period." Because the DSIs now know that the IOUs have not filed petitions for review challenging the DSIs power sales and because the IOUs will not file petitions to challenge the DSIs' rates, the DSIs may not challenge the IOUs' REP Settlement Agreements.

Through discussions with a mediation attorney with the Ninth Circuit, BPA and the parties to all of the above-noted litigation agreed to stay the litigation pending settlement discussions. These settlement discussions have led to the development of a litigation settlement, including the proposed amendments to the IOUs' REP Settlement Agreements and the development of the Slice Settlement Agreements, described in greater detail below, that is the subject of this ROD.

H. BPA's 2002 Wholesale Power Rate Case

On August 13, 1999, BPA published a notice of BPA's *2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment*. 64 Fed. Reg. 44,318 (1999). This began a lengthy and complex hearing process that concluded with BPA's *2002 Final Power Rate Proposal, Administrator's Record of Decision*, in May 2000 (May Proposal). 16 U.S.C. § 839e(i). In July, 2000, BPA filed its proposed 2002 wholesale power rates with the Federal Energy Regulatory Commission (FERC) for confirmation and approval. 16 U.S.C. § 839e(a)(2). Subsequent to that time, however, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before in the West. By August, it was clear that these market prices were not a short-term phenomenon. This meant that BPA's cost-based rates, which were already below the original market forecast, were even more attractive. Thus, BPA assumed that additional load would be placed on BPA, and BPA would need to purchase additional power to augment the Federal Columbia River Power System (FCRPS) supply. BPA determined that the implications for cost recovery were so serious that a stay of the rate proceeding at FERC was requested. This enabled BPA to review the events that had occurred during the summer months and to determine whether the escalating prices and increased volatility would require remedial action.

Escalating and more volatile market prices had two related effects. First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. Second, to meet this increased load obligation, BPA would need to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. BPA concluded that the May Proposal, as filed with the FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA.

During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources by 1,732 average megawatts (aMW). Due to escalating and volatile market prices, BPA estimated that expected loads would exceed the original rate case forecast by an additional 1,518 aMW. Inasmuch as the generating capability of FCRPS was already inadequate to meet the earlier load forecast, BPA would have to purchase to further augment its inventory to serve these additional loads. The cost of power to serve these unanticipated loads was not included in revenue requirements.

The combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminished the probability that rates proposed in the May Proposal would fully recover generation function costs. Absent a change to the May Proposal, Treasury Payment Probability (TPP) would be reduced to below 70 percent, a level that would fall well short of specific goals and targets. In its judgment, BPA had a serious cost recovery problem that it was obliged to address by reason of statute and Administration policy.

BPA's Amended Proposal rate case was a continuation of the WP-02 rate proceeding. It was 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. BPA then filed a Supplemental Proposal. 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

FY 2001 and for the next five years of the rate period – 102.4 million acre feet (MAF). By contrast, FY 2001 was shaping up to be the second lowest runoff year on record, with runoff forecasted at under 60 MAF. These conditions would require BPA to purchase much more power in FY 2001 than expected to meet loads, at extremely high prices, and to reduce the amount of surplus energy BPA could sell that 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 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. Even then, numbers were uncertain due to 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 with other tools needed to be made.

Because BPA would likely be in the market purchasing power to serve load during the next five years, BPA's purchase power costs would fluctuate as market prices change. Because the potential levels of power purchases and prices were so great, BPA needed 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 acceptable level, all other things being equal, the expected value for the average rate over the five years would be higher with an average flat rate than with a rate shaped to match the expected market. Therefore, BPA revised the LB CRAC so that its expected revenues closely matched the shape of its augmentation costs. In summary, BPA's Supplemental Proposal suggested that BPA's customers could see much higher prices during the October 1, 2001, to September 30, 2006, rate period.

On June 20, 2001, BPA issued the "2002 Supplemental Power Rate Proposal, Administrator's Final Record of Decision, WP-02-A-09." The Final ROD adopted three Cost Recovery Adjustment Clauses (CRACs). These CRACs included the LB CRAC, which is designed to recover augmentation costs; the FB CRAC, which is designed to recover limited net revenue shortfalls; and the SN CRAC, which is designed to provide a "safety net" in case BPA's financial situation continues to deteriorate despite implementing the LB and FB CRACs. Together, these CRACs allowed BPA to adopt a general approach of keeping base rates low and addressing financial shortfalls, as needed, through the implementation of the CRACs. These tools provided BPA the risk mitigation necessary to establish an acceptable level of Treasury Payment Probability (TPP) for BPA's proposed 2002 power rates.

I. Administrator's Call for Rate Mitigation Efforts

On April 9, 2001, the BPA Administrator delivered a speech to the citizens of the Pacific Northwest regarding the potential impact of BPA's proposed rate increase and possible ways to reduce the impact of the increase. The text of the speech follows:

> Last January, I sent out a letter to Northwest citizens that caused some shock waves. That was my intent. I believe it is important to warn of bad news while there is still time to take actions that can lessen the impact. At the time, I said that, if certain conditions persisted, BPA's customers--Pacific Northwest utilities and direct-service industries--could face a significant rate increase for the wholesale power they buy from the Bonneville Power Administration. The figures I cited then were for an average rate increase of 60 percent over the five-year rate period that starts this coming October. I cautioned that the increase could be as high as 90 percent in the first year.
>
> Unfortunately, the situation has worsened. It now appears possible that, without the kinds of action that I am about to call for today, the first-year increase could be 250 percent or more. If that were to occur, it likely would translate into doubling the retail rates in many utility service areas.
>
> An increase of this magnitude would have widespread economic consequences. Already, we are seeing some businesses curtail operations or even close as a result of high energy prices. With such an increase, we'd surely see more businesses close and more job losses, with people with lower incomes suffering disproportionately. In addition, a weak economy frequently translates into less public support for environmental protection.
>
> I don't believe these consequences are acceptable. More importantly, I don't believe they are inevitable. That's why I am here today to call for some very specific actions and to call on all stakeholders in the Pacific Northwest to own part of the process that will help us avert an economic blow to our region. I believe we can get the rate increase down to a manageable level, but we need to make some tough decisions, and we have little more than 60 days to do this. BPA's rates, which will go into effect in October, should be submitted to the Federal Energy Regulatory Commission in June.
>
> First, let me review what has led us to this point. Some of it you already know. We are experiencing the second worst water year in 72 years of record-keeping. According to a report released by the Northwest Power Planning Council, if the drought persists, the hydropower generating capability in the Northwest from March through August will be 4,700

megawatts below normal over those months--the equivalent power consumed by four Seattles. The implications are ominous since the Northwest relies on hydropower for nearly three-quarters of its electricity.

But the summer drought is only the immediate crisis. We are becoming increasingly concerned about power supply for the coming winter. Canadian reservoirs, which store half the system's water, are extremely low this year, which means we could start next year with less than a full tank. If that were to happen, and especially if we have a second dry year in a row, electricity reliability wouldn't be the only thing at risk. Low reservoir levels also raise concerns for salmon and steelhead next year.

Low water combined with a tight wholesale power market and skyrocketing power prices is a devastating combination. The fiasco in California has helped drive wholesale electricity prices to unprecedented levels. When we completed our new Subscription power contracts last fall, BPA's contractual obligations added up to approximately 11,000 megawatts--about 3,000 megawatts more than our current generating resources can provide on a firm basis. The only way we can meet our obligations is to buy the vast majority of the additional power in a wholesale power market where supplies are tight and prices are sky high. This is what is driving rates up.

This year, due to the high power prices, BPA has not been able to purchase sufficient power to ensure system reliability. Consequently, we have periodically declared power system emergencies. These emergency declarations have allowed us to increase power generation from the river and reduce operations that offer benefits to migrating juvenile fish. The increased generation has reduced the amount of water that is normally stored at this time of year so that it can be used to augment spring and summer river flows. While there may be some impact on fish, by far the major impact on fish is the drought itself, not the emergency power operations. We are continuing to implement all other aspects of the federal measures for fish recovery.

Currently, we are operating the river on an emergency basis, and we can continue some fish spill or flow augmentation only as long as water volume does not dip much below current estimates. The record low runoff is a water volume of 53 million-acre feet. As of last week, the volume forecasts had dropped to 56 million-acre feet, which is 53 percent of the normal runoff. This severely limits our flexibility to do much more than meet power needs.

Beyond the current drought, high power prices are expected to continue until significant new generation and additional conservation measures are put in place. This will take a couple of years at best. And, we can’t expect much help from Canada, which also is suffering drought, nor any help from California, which is in the throes of an electricity restructuring crisis.

We must focus instead on what we can control if we expect to minimize the size of the coming wholesale rate increase. The most immediate and direct way to decrease the size of next year's rate increase is quite simply to decrease the amount of power BPA has to buy in the market.

We already have taken a number of extraordinary steps in this direction. We have promoted conservation aggressively and sought voluntary curtailments in power use. We have begun to purchase curtailments from our direct service industrial customers and from irrigators who are served by our utility customers. We have offered innovative incentives for development of conservation and renewables, and we have engaged in beneficial 2-for-1 power exchanges with California. We also are continuing to collaborate with the Corps of Engineers and Bureau of Reclamation to increase the productive capability of the federal power system.

But even these extraordinary measures haven't been enough in the face of the triple whammy of historic low water conditions, an extremely tight power market and enormous volatility in power prices. We now need to up the ante if we are to get the rate increase for the next year down to a manageable level.

We literally are at a crossroads, and the region has essentially two options. Path A is to wait and see where market prices settle in June. Under this scenario, we'd rely on cost recovery mechanisms to kick up rates if prices remain high. We would take no special actions and we wouldn't push or negotiate with our customer groups to secure load reductions. The risk is that, if market prices stay the same, we could expect to see a first year rate increase in the 200 to 300 percent range, and possibly greater.

Then there's Path B, which calls for aggressive and immediate steps to reduce the size of the rate increase by reducing the amount of electricity demand put on BPA. Under this scenario, BPA would not have to buy as large an amount of power in a very expensive wholesale power market. It's a strategy that calls on our customers and other stakeholders to share a sacrifice by reducing their demands for power. It requires significant, and I mean significant, contributions from all customer groups. It could keep the first-year rate increase below 100 percent. I believe Path B is the course we must choose, so let me lay out some of the actions that will move us along this path.

As I discuss this path, let me outline the principles I believe are key to reducing rates. First, rates must be set to cover costs if we are to avoid creating a credit problem, which could lead to refusals to sell to us in the future. We must also cover our costs to ensure we preserve the benefits of the federal hydropower system over the long term, which is essentially the bottom line.

Second, the situation is urgent. We must act quickly because rates must be in effect this coming October 1. As I said earlier, our rate proposal is due in to the Federal Energy Regulatory Commission in June.

Third, our problem is caused by a significant exposure to a volatile market in the first one-to-two years of the rate period. If we are to manage a reduction in the rate increase, we must reduce our exposure to that market by reducing demand for energy, increasing our supply and minimizing the short and long-term damage to the region's economy.

Fourth, contributions to the solution are needed from all customers. We can't play a game a chicken where each party waits for the other to step forward. If that happens, no one will step forward. Each group must contribute if we are to preserve an equitable distribution of the benefits of our hydropower resource.

…

Given those principles, let me outline the actions we as a region need to take. We need a three-pronged approach that includes curtailment of power use, conservation--or more efficient use of power--and power buybacks. This needs to happen across all four states, across public and private power, and across all sectors of energy use--industrial, commercial, agricultural and residential. It will take all of us working together if we are to avoid severe economic hardships for the region. Let me be clear; what I am about to suggest requires a great deal of sacrifice, but the alternative is to suffer far more serious consequences. We are beginning negotiations now with our customers. If people don't come to the table with reductions in their demand for electricity, a very large and very damaging rate increase is inevitable.

First, we are calling on our public utility customers to make a contribution to the solution. We need every utility customer to reduce its Subscription purchases from BPA by 5 to 10 percent. BPA's rate increases will spur some of this reduction, but more focused efforts are needed if we are going to achieve significant savings. We are willing to make modest incentive payments to help achieve this, but the incentive payments cannot be large or they will defeat the intended effect.

We are running several demand-side management initiatives including a conservation and renewables discount, a conservation augmentation program and a demand exchange program.   In addition, we now are discussing the potential for new programs to provide incentives to our public utility customers to adopt innovative retail rate structures that encourage their consumers to conserve energy.

Second, we are calling on investor-owned utilities to make a contribution. When our new rates go into effect this October, investor-owned utilities--or IOUs--will receive sizable benefits from BPA for their residential and small farm customers as a result of a the residential exchange. Under this program, as it is set out in the Subscription period, 1,900 average megawatts of financial and power benefits are scheduled to go to the IOUs**.** But, because of dramatic changes in market prices, the estimated value of these benefits has increased enormously since they were negotiated a year ago. By 2002, the value will be 10 times higher than the negotiations intended to capture. As a result, IOUs are in a position to reduce their Subscription demand significantly and still enjoy benefits in excess of anything they have experienced in the 20-year history of the residential exchange.

Third, we are asking our direct service industries--or DSIs--to agree not to take power from us for up to the first two years of the rate period in return for certain limited compensation to the companies and their workers. It is our expectation that the companies would not be able to operate given a potential tripling of our rates anyway. Coming to an agreement now that the plants will not operate would allow BPA to avoid making power purchases, thereby decreasing our rates for all remaining customers.

It is not our intention to drive the aluminum industry out of the region, but we are continuing to encourage the industry to move off of BPA power supplies after the 2006 rate period because we do not have a statutory obligation to continue to serve them. The customers we are obligated to serve--the region's retail electric utilities--need more than our current generation resources can produce. We will work with these companies to help them find a means to operate profitably in the long run without relying on BPA.

Almost all of the DSIs are already shut down until this fall, and their power is being remarketed to support Northwest needs during the current drought. These buydowns played a key role in keeping the lights on this winter and in maintaining reservoir levels higher than they otherwise would have been.

Fourth, I am urging all citizens of the Northwest to heed the call of our governors to reduce electricity consumption by 10 percent through eliminating waste and using electricity more efficiently. There are a number of common sense measures we can all take, and one good place to start right now is to go out and replace conventional light bulbs with compact fluorescents, which consume about 20 percent of the electricity used by regular bulbs for the same amount of light.

These four sets of actions that I have described are urgently needed between now and June if we are to avert grave near-term economic consequences. These are difficult actions. But, with hindsight, we can learn from the problems California experienced and seek to avoid them. We need to do everything we can to avoid power purchases in this incredibly expensive market. We also need to make sure we set rates high enough so we can cover our costs to assure generators get paid when they deliver power on a contractual basis so we don't put our credit at risk.

We also are looking to longer-term solutions that will help lead to lowering the incredible wholesale power supply prices we are currently experiencing. The fundamental problem is supply and demand being out of balance. Prompt infrastructure investments are needed in generating resources, especially gas-fired and wind-powered generation; gas pipeline capacity and storage; electric power transmission facilities; and energy conservation measures.

BPA's [proposed] rates [may] now be set on a six-month basis based on our actual costs. If wholesale power prices can be brought down quickly, through infrastructure investments and other actions, then our rates will come down in the future. The faster these actions can be taken, the quicker our rates can come down.

We already have begun plans to shore up the transmission infrastructure, and we are negotiating to purchase the output from combustion turbines and new renewable resources. We also are increasing our efforts to encourage and procure energy efficiency. We are working to implement these actions quickly, but at best, some actions, such as securing more generation, will take one-to-two years.

That's why I am calling for cooperation and sacrifices for the next two years from all parties BPA serves. If the region cannot or will not take the actions necessary to reduce the rate hike, we have no recourse but to set our rates to recover our costs. BPA does not receive subsidies from taxpayers. We must wholly cover our costs with revenues we receive from sales of power and transmission. We are obligated to repay, with interest, all capital investments that have been made by the federal government in the facilities that are part of the Northwest's federal power system. Already, we have drawn on our financial reserves heavily this winter, and more of the same still may be ahead of us.

> Some have suggested that we can simply fail to pay one of our largest creditors--the U.S. Treasury--rather than declare power emergencies or raise rates sharply. While there is no absolute guarantee we will make our full Treasury payment this October, I believe we should use all management tools available to do so. Our ability to pay our debt in full and on time is the best protection the Northwest has to preserve the benefits of the Columbia River hydropower system for the region. There are interests outside the region that want to see the benefits of this system directed toward other purposes. They could take great political advantage of the opportunity that would be presented if BPA did not cover its costs. One consequence could be the loss of cost-based rates for power from the federal system. We have seen how exorbitant market rates can be. If that were to happen, the region would be looking at far higher rate increases than we are now facing.
>
> So, in closing, let me underscore the message. We are on a trajectory that poses grave consequences for the Pacific Northwest, primarily due to extraordinary conditions beyond our control--extremely low water, an extremely tight power supply and extremely high wholesale power prices. We believe the only alternative to a huge rate hike is to reduce our exposure to the market in the first two years of the next five-year rate period by reducing the Subscription demand on BPA. It will take major contributions from all our customers if we are to prevent a triple digit rate increase. And, we will need to make these very difficult decisions very quickly.
>
> Finally, we believe this proposal, while not an easy one to achieve, fairly balances the sacrifices the region needs and does not unfairly hit one customer group or one state over others. I know putting these proposals into place will be tough, but I believe the consequences of not taking this path will even be tougher.

Thus, the Administrator asked the regional IOUs to contribute to the mitigation of BPA's potentially difficult rate increases.

J. Load Reduction Agreements: Amendments To PacifiCorp's And Puget's REP Settlement Agreements

As noted previously, the Northwest Power Act establishes a Residential Exchange Program to provide benefits to residential and small farm consumers of Pacific Northwest utilities. BPA implements the REP through the offer, when requested, of a Residential Purchase and Sale Agreement. In October, 2000, BPA and all regional IOUs entered into contracts (the "REP Settlement Agreements") for the purpose of settling disputes over implementation of rights and obligations for the REP under the Northwest Power Act. These Settlement Agreements provided, among other things, for BPA to provide the

IOUs with Firm Power and Monetary Benefits to settle the REP. The term of the Settlement Agreements continue through September 30, 2011. BPA executed Settlement Agreements with all of the IOUs, including PacifiCorp and Puget.

BPA and PacifiCorp negotiated a letter agreement (Amendment No. 1), which constitutes an amendment to PacifiCorp's Residential Exchange Program Settlement Agreement, Contract No. 01PB-12229, executed by BPA and PacifiCorp. BPA and PacifiCorp agreed that BPA would, rather than deliver firm power to PacifiCorp for the first five years of the Settlement Agreement, make cash payments during the period that begins October 1, 2001, and ends on September 30, 2006. These cash payments are made under a Financial Settlement Agreement, Contract No. 01PB-10854. Amendment No. 1 removes BPA's obligation to deliver firm power for the first five years of the Settlement Agreement. BPA and PacifiCorp executed Amendment No. 1 and the Financial Settlement Agreement simultaneously.

Similarly, BPA and Puget agreed that BPA would, rather than deliver Firm Power to Puget for the first 5 years of the Settlement Agreement, make cash payments to Puget during the period that begins October 1, 2001, and ends on September 30, 2006. BPA would use the Firm Power not sold to Puget to meet deficits in resources necessary to meet loads of publicly owned and cooperative customers in its firm load obligations in the Pacific Northwest. BPA and Puget also agreed to extend the term of the settlement under the Amended Settlement Agreement (Agreement) through the period from October 1, 2006, through September 30, 2011, on the same terms and conditions as are in the corresponding Residential Exchange Settlement Agreements and Firm Power Block Sales Agreements for other investor-owned utilities for such period.

BPA and Puget entered into the Amended Settlement Agreement in order to supersede the Settlement Agreement in its entirety for the purpose of replacing the delivery of Firm Power by BPA to Puget with cash payments during the period that begins October 1, 2001, and ends on September 30, 2006; extending the term of the Settlement Agreement until September 30, 2011; and affirming the intent to settle rights and obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act.

Both section 4(b), footnote 2 of PacifiCorp's Financial Settlement Agreement, Contract No. 01PB-10854, and section 4(b)(1)(B), footnote 2 of Puget's Amended Settlement Agreement, Contract No. 01P-10885, provide that the respective utilities are willing to reduce the amount of benefits received under their agreements. These benefit reductions only occur in the event that the respective utilities have entered into settlement agreements with certain publicly owned utility and cooperative customers that waive and dismiss legal challenges, *inter alia*, to the respective utilities' original REP Settlement Agreements. In order to reduce PacifiCorp's and Puget's reduction of risk benefits, litigation settlements with publicly owned utility and cooperative customers had to occur by December 1, 2001. The amount of the reduction in risk benefits, for PacifiCorp and Puget combined, is approximately $200 million. Absent settlement, the $200 million would be included in and recovered through BPA's wholesale power rates.

K. Conditional Deferral Agreements

In June of 2002, PacifiCorp and Puget executed “Agreements Regarding Conditional Deferral Of Reduction Of Risk Discount Amount.” Pursuant to Section 4(b) of the Financial Settlement Agreement (Contract No. 01PB-10854) between BPA and PacifiCorp (Financial Settlement Agreement), PacifiCorp would have accepted a “Reduction of Risk Discount” commencing October 1, 2002, if by December 1, 2001, it entered into specified settlement agreements with one or more of BPA’s publicly-owned utility and cooperative customers. Similarly, pursuant to Section 4(b)(1)(B) of the Amended Settlement Agreement (Contract No. 01PB-10885) between BPA and Puget (Financial Settlement Agreement), Puget would have accepted a “Reduction of Risk Discount” commencing October 1, 2002, if by December 1, 2001, it entered into specified settlement agreements with one or more of BPA’s publicly-owned utility and cooperative customers. Such specified settlement agreements, however, were not entered into by December 1, 2001, and the absence of such settlements would have affected the revenue requirement that BPA would have included in its LB CRAC adjustment to its wholesale power rates effective October 1, 2002.

As of the effective date of the Agreements Regarding Conditional Deferral Of Reduction Of Risk Discount Amount, discussions between PacifiCorp, Puget, and various parties, including BPA preference customers, regarding a comprehensive settlement of various BPA matters, including litigation relating to Contract No. 01PB-12229 or the Financial Settlement Agreement for PacifiCorp, and Contract No. 01PB-12162 or the Amended Settlement Agreement, were at an advanced stage. It was an objective of such discussions to develop and execute a new agreement between BPA and PacifiCorp and BPA and Puget pursuant to which PacifiCorp and Puget would, for a period commencing FY 2007, receive payments from BPA for the benefit of their residential and small farm customers pursuant to implementation of or in settlement of the residential exchange provisions of the Northwest Power Act. BPA preference customers had asked that any such settlement, if successful, include a reduction in payments under the Financial Settlement Agreement equal to the Reduction of Risk Discount, and that PacifiCorp and Puget defer collection of the amounts covered by the Reduction of Risk Discount while settlement discussions continued.

The deferral period under the “Agreements Regarding Conditional Deferral Of Reduction Of Risk Discount Amount” began October 1, 2002, and continues until termination of the deferral period. The deferral period continues automatically for 6-month periods beginning October 1, 2002, unless PacifiCorp and Puget elect, by notice to BPA not less than 120 days prior to the beginning of any such 6-month period, for a reason specified below, to terminate the deferral period at the end of such 6-month period. PacifiCorp and Puget have the right to terminate the deferral period under the Financial Settlement Agreement if: (a) PacifiCorp determines that the current comprehensive settlement efforts regarding litigation relating to Contract No. 01PB-12229 or the Financial Settlement Agreement are unlikely to be concluded successfully to PacifiCorp’s satisfaction; or Puget determines that the current comprehensive settlement efforts regarding litigation relating to Contract No. 01PB-10885 are unlikely to be concluded successfully to Puget's satisfaction; or (b) the Washington Utilities and Transportation Commission, the Public Utility Commission of Oregon, or the Idaho Public Utilities Commission, as applicable, objects to or disapproves continuation of the deferral period. PacifiCorp's and Puget's reduction of risk benefits are currently being deferred.

L. Financial Choices

On July 2, 2002, BPA sent a letter to rate case parties and other interested entities in the region announcing the beginning of the Financial Choices public comment process. The Financial Choices process examined a variety of financial and program options for addressing PBL's FY 2003-2006 financial challenges. In this process, BPA described the financial challenges, the actions BPA already had taken to address the problem, and the financial outlook for the remainder of the rate period. Additionally, BPA identified a variety of potential financial alternatives that, separately or in combination, could form the basis of a solution to PBL's financial situation.

During the course of the process, BPA held ten public meetings and workshops with customers, public interest groups, tribes, and other interested persons to explain the nature of the problem, and to show program level costs and the potential effects of cost reductions. BPA also solicited suggestions to address its growing financial problem. The public comment period for the Financial Choices process closed on September 30, 2002. As a result of the Financial Choices process, BPA made decisions to cut, eliminate, or defer certain costs and expenses. BPA issued a Financial Choices close-out letter to the region on November 22, 2002, outlining BPA's plan, in part, for meeting the agency's financial challenges. The plan took into consideration extensive public input BPA received during the Financial Choices public process. The BPA actions described in the Financial Choices close-out letter included $350 million in expense savings, expense deferrals, and other actions for the FY 2003-2006 period. These were reflected in the program levels in BPA's initial proposal. Included among such other actions were agreements with the IOUs to defer $55 million in benefits from FY 2003 to FY 2007-11, discussed immediately below. The $55 million deferral was subject to the SNCRAC offsets discussed in Section D(1) of this ROD.

M. FY 03 Deferral Agreements

As noted previously, in late 2000, the IOUs entered into Settlement Agreements with BPA, which settled BPA's and the IOUs' rights and obligations during the period from July 1, 2001, through September 30, 2011, under or arising out of section 5(c) of the Northwest Power Act. In June of 2002, BPA entered into "Agreements Regarding Conditional Deferral of Reduction of Risk Discount" with PacifiCorp and Puget, which amended the payment provisions of the Financial Settlement Agreement and Amended Settlement Agreement, respectively, to provide for conditional deferral of payment by BPA of certain amounts to be paid under the Financial Settlement Agreement and Amended Settlement Agreement. In late 2002, BPA sought to defer payment in FY 2003 of certain amounts of monetary benefits under the IOUs' Settlement Agreements and to facilitate a relatively uniform pass-through of benefits under the Settlement Agreements. In early 2003, BPA contemporaneously entered into agreements under which the IOUs and BPA agreed to deferral of payments in FY 2003 under agreements amending provisions of the Settlement Agreement, known as "Agreements Regarding Fiscal Year 2003 Deferral Amount." These agreements include: Avista Corporation, Contract No. 03PB-11265; Northwestern Corporation, Contract No. 03PB-11269; PacifiCorp, Contract No. 03PB-11262; Portland General Electric (PGE), Contract No. 03PB-11267; Puget Sound Energy, Inc. (Puget), Contract No. 03PB-11251; and Idaho Power Company, Contract No. 03PB-11268. The total cumulative amount to be deferred under these agreements equaled $55 million.

N. SN CRAC Trigger

The SN CRAC is one of three CRACs that are part of BPA's power rate design in BPA's WP-02 rates. The other two CRACs are the LB CRAC, which is designed to recover augmentation costs, and the FB CRAC, which is designed to recover limited net revenue shortfalls. The SN CRAC is designed to provide a "safety net" in case BPA's financial situation continues to deteriorate despite implementing the LB and FB CRACs. Together, these CRACs, as established in BPA's Supplemental Proposal of June 2001, allowed BPA to adopt a general approach of keeping base rates low and addressing financial shortfalls, as needed, through the implementation of the CRACs. These tools provided BPA the risk mitigation necessary to establish an acceptable level of Treasury Payment Probability (TPP) for BPA's proposed 2002 power rates.

The SN CRAC is said to "trigger," that is, the Administrator may begin a section 7(i) hearing to determine whether or not BPA requires an SN CRAC adjustment, upon a finding by the Administrator regarding the likelihood of making Treasury payments. Section II.F.3 of BPA's 2002 GRSPs provides:

> The SN CRAC will be available if the Administrator determines that, after the implementation of the FB CRAC and any Augmentation True-Ups, either of the following conditions exist:
>
> - BPA forecasts a 50 percent or greater probability that it will nonetheless miss its next payment to Treasury or other creditor, or
>
> - BPA has missed a payment to Treasury or has satisfied its obligation to Treasury but has missed a payment to any other creditor.

Under section II.F.3.b, entitled "SN CRAC Hearing Process," triggering the SN CRAC starts an expedited 40-day section 7(i) hearing to establish changes to the FB CRAC parameters.

On February 7, 2003, the Administrator sent a letter to customers, tribes, constituents, and interested parties advising them of his determination that the SN CRAC had triggered, based on the first of the above criteria. That same day, BPA's Manager of

Power Products, Pricing, and Ratemaking sent a second letter to interested parties and customers informing them of this determination. This letter included a table summarizing the documentation used by BPA to determine that the SN CRAC had triggered, the amount of the forecasted shortfall, and the time and location for a workshop on the SN CRAC. This workshop was held February 11, 2003. Those letters reflected BPA's financial condition at that time. BPA thereafter started the SN CRAC process: BPA forecasted a 50 percent or greater probability that it would miss its next payment to Treasury; and it sent written notification of the determination to customers with documentation used by BPA to determine that the SN CRAC process had triggered, including the amount of the forecasted shortfall, and the time and location of the SN CRAC workshop.

O. SN CRAC Implementation Rate Hearing

By January 2003, BPA projected that worsening water conditions and a refined secondary revenue forecast increased BPA's net revenue gap for the 2002-2006 rate period to $920 million. On February 7, 2003, the BPA Administrator determined that the SN CRAC triggered based upon a forecast of a 50 percent or greater chance of missing a payment to the U.S. Treasury or another creditor during this fiscal year. The triggering of the SN CRAC initiated an expedited hearing under section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(i). Prior to the release of its initial SN-03 rate proposal, BPA sponsored six workshops in order to address a variety of issues related to its ratemaking.

On March 13, 2003, BPA published a Federal Register Notice of "Proposed Safety-Net Cost Recovery Adjustment Clause Adjustment to 2002 Wholesale Power Rates," 68 Fed. Reg. 12048 (2003). BPA's SN-03 proceeding began with a prehearing conference held on March 31, 2003. BPA issued the "2003 Safety Net Cost Recovery Adjustment Clause Final Proposal, Administrator's Final Record of Decision, SN-03-A-02," on June 30, 2003. The Final ROD described the implementation of the SN CRAC during the remainder of the FY 2002-06 rate period.

In its Final ROD, at the conclusion of the hearing, BPA noted that the regional economy is extremely weak. This was documented in BPA's 2002 Wholesale Power Rate Adjustment Proceeding, and in BPA's 2003 SN CRAC Rate Proceeding. Several parties noted the poor state of the Northwest economy. Golden Northwest Brief, SN-03-B-GN-01, at 13; ICNU/ALCOA Brief, SN-03-B-IN/AL-01, at 12; NRU Brief, SN-03-B-NR-01, at 4; PNGC Brief, SN-03-B-PN-01, at 3; PPC/IEA Brief, SN-03-B-PP-01, at 10; WPAG Brief, SN-03-B-WA-01, at 2. Parties expressed concern over the potential impact an SN CRAC might have on the Northwest economy. "[T]estimony from numerous parties confirms that the economy in the Pacific Northwest is mired in the worst recession in the Nation." Golden Northwest Brief, SN-03-B-GN-01, at 13. "Many customers emphasized the stagnant economy and the harm that a further BPA rate increase would impose on the Region." ICNU/ALCOA Brief, SN-03-B-IN/AL-01, at 12. "BPA's customers have shown that, at both the utility and end use customer level, another rate increase would further harm an already poor economy." NRU Brief, SN-03-B-NR-01, at 4. "Numerous regional utility customers of BPA and of [sic] some of their major retail customers have submitted testimony that shows that the Region cannot afford an SN CRAC charge without placing at risk many, many jobs in the Region." PNGC Brief, SN-03-B-PN-01, at 3. "[A] rate increase would be very harmful to the economy." PPC/IEA Brief, SN-03-B-PP-01, at 10. "When BPA commenced this proceeding, the economy of the Northwest was gripped by a severe economic recession. . . . These circumstances have not improved during the intervening three months." WPAG Brief, SN-03-B-WA-01, at 2. BPA was concerned about the impact of any rate increase on the economy of the Pacific Northwest, so direction was given to staff that the rate design should mitigate the level of any rate increase, to the extent possible. Keep, *et al*., SN-03-E-BPA-04, at 13.

In order to regain its financial health, BPA's initial proposal set a prospective rate level of 15.6 percent (average expected value rate level for FY 2004–2006 above the total average rate level for FY 2003). The implications of such a large rate increase for a fragile Northwest economy were of great concern, but so were the long-term implications if BPA failed to recover its costs through its rates. Over the course of months during which the hearing took place, the prognosis changed for the better. These improvements included aggressive cost cutting resulting in over $80 million in net expense reductions, more favorable water conditions, higher market prices, and cash benefits from debt optimization, among other things. In light of these improvements to BPA's financial health, the Administrator reconsidered the need to adopt two addition financial standards as initially proposed (TRP and zero net PBL Revenues in addition to TPP). BPA instead returned to relying on a single financial standard, requiring that the three-year TPP be at least 80 percent.

BPA was still concerned about the level of BPA's rates in a weakened economy. In the Final Supplemental ROD, BPA noted "BPA will continue to seek further cost reductions." 2002 Final Supplemental ROD, SN-03-A-02, at 2.1-9. In response to parties' comments that BPA should reduce its costs further, BPA noted ". . . if public agency customers and IOUs reach a settlement of litigation challenging the IOUs' Residential Exchange Program settlements, BPA's [revenue requirement] will be greatly reduced which could reduce the level of BPA's rates." *Id*. at 2.1-16-17. Indeed, such a settlement would in effect provide for the continuation of the Reduction of Risk Discount through September 30, 2006, thus reducing BPA's revenue requirement by approximately $200 million. In addition to the $200 million reduction and the existing $55 million IOU deferral of benefits into the FY2007-11 period, additional deferrals of $75 million per year for the remaining three years of the rate period ($225 million, as discussed below) would lead to a total reduction in BPA's revenue requirement in the rate period of approximately $480 million. Such a rate reduction would be of enormous benefit to the region during troubled economic times.

DISCUSSION

I. LITIGATION SETTLEMENT

A. BPA's Broad Settlement Authority

Given the foregoing context, BPA and its customers identified an opportunity to resolve many of the outstanding issues pending among them. This could be achieved through a settlement of outstanding litigation, implemented in a manner consistent with BPA's settlement authority. In 1937, Congress granted the BPA Administrator broad discretion, beyond that which is normally provided to government agencies, to take such actions as the Administrator determines to be appropriate and necessary in accordance with sound business principles. Section 2(f) of the Bonneville Project Act, as amended, states that:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof, and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.

16 U.S.C. § 832a(f).

Congress carried forward this broad authority into subsequent legislation. In the Department of Energy Organization Act, 42 U.S.C. § 7152(a) (2000), Congress expressed the intent that this authority remains unabridged as the functions and authorities of the Secretary of the Interior were transferred to the new Department of Energy. S. Rep. No. 95-164, at 30 (1977). Congress again affirmed this broad authority in 1980 when it enacted the Northwest Power Act. Section 9(a) of that Act states that "[s]ubject to the provisions of this chapter, the Administrator is authorized to contract in accordance with section 2(f) of the Bonneville Project Act of 1937 (16 U.S.C. § 832a(f))." 16 U.S.C. § 839f(a).

BPA's broad settlement authority has also been affirmed by the United States Court of Appeals for the Ninth Circuit. *APAC*, 126 F.3d 1158 (9th Cir. 1997); *Vulcan Power Co. v. Bonneville Power Admin.*, 89 F.3d 549 (9th Cir. 1996); *Utility Reform Project v. Bonneville Power Admin.*, 869 F.2d 437, 442-443 (9th Cir. 1989).

B. Litigation Settlement And Rate Reduction

As noted previously, petitioners PGE, No. 01-70003; PacifiCorp, No. 01-70005; the Public Power Council, No. 01-70010; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70012; Puget Sound Energy, Inc., No. 01-70041; and Atofina Chemicals, Inc., Columbia Falls Aluminum Co., Goldendale Aluminum Co., Kaiser Aluminum & Chemical Corporation, and Northwest Aluminum Co., No. 01-70042; filed petitions for review in the United States Court of Appeals for the Ninth Court challenging BPA's Residential Exchange Program Settlement Agreements with its regional IOU customers. (Agreements had been entered into between the Bonneville Power Administration and all of the IOUs, namely Subscription Settlement Agreements (and amendments, exhibits, modifications, or replacements) including Contract No. 00PB-12157, Contract No. 00PB-12163, and Contract No. 03-PB-11265 with Avista Corporation; Contract No. 00PB-12158, Contract No. 00PB-12164, and Contract No. 03PB-11268 with Idaho Power Company; Contract No. 00PB-12160, Contract No. 00PB-12165, and Contract No. 03PB-11269 with Northwestern Energy; Contract no. 01PB-12229, Contract No. 01PB-12230, Contract No. 01PB-10854, Contract No. 02PB-11157, and Contract No. 03PB-11262 with PacifiCorp; Contract No. 01PB-10885, Contract No. 01PB-10886, Contract No. 02PB-11156, and Contract No. 03PB-11251 with Puget Sound Energy; and Contract No. 00PB-12161, Contract No. 00PB-12167, and Contract No. 03PB-11267 with Portland General Electric Company).

Also, petitioners Portland General Electric Company, No. 01-70002; PacifiCorp, No. 01-70008; the Public Power Council, No. 01-70009; Benton Rural Electric Association, *et al*. (including approximately 51 other public agencies), No. 01-70014; Avista Corporation, No. 01-70020; Puget Sound Energy, Inc., No. 01-70041; and Northwest Aluminum Co., *et al*., No. 01-70060; filed petitions for review in the Ninth Circuit challenging BPA's proposed Residential Purchase and Sale Agreements.

Petitioner Puget Sound Energy, No. 01-70202, filed a petition for review in the Ninth Circuit challenging BPA's offer of the Block and Slice Power Sales Agreements to its preference customers. Petitioners Pacific Northwest Generating Company (PNGC), Blachly-Lane County Cooperative Electric Association, Central Electric Cooperative, Inc., Consumers Power, Inc., Coos-Curry Electric Cooperative, Inc., Douglas Electric Cooperative, Lane Electric Cooperative, Lost River Rural Electric Cooperative, Northern Lights, Inc., Oregon Trail Electric Consumers' Cooperative, Raft River Rural Electric Cooperative, and Umatilla Electric Cooperative Association, No. 00-70948; and Puget Sound Energy, No. 00-70949; filed petitions for review in the Ninth Circuit challenging BPA's Supplemental Subscription Strategy and Record of Decision.

Also as noted above, BPA had determined the manner in which it would implement the SN CRAC. BPA's proposal called for an increase in BPA's rates. BPA noted, however, that BPA's proposed rate increase could be eliminated, and a significant rate decrease adopted, in the event of a litigation settlement. This was because the proposed settlement could reduce BPA's revenue requirement by $200 million, in effect providing for the continuation of the Reduction of Risk Discount through September 30, 2006, and an additional $225 million over the remaining three years of the rate period through the deferral of IOU benefit payments to the FY 2007-11 period. The earlier $55 million in deferrals would be further deferred to the FY 2007-11 period without the SNCRAC offsets discussed in Section D(1) of this ROD.

After the foregoing petitions had been filed, the parties agreed to stay the petitions pending settlement discussions. Negotiations had been ongoing since the summer of 2001. Renewed negotiations to settle these outstanding cases between BPA, the IOUs and BPA's preference customers commenced in February 2003. The negotiating parties then developed a Stipulation for Settlement. The parties recognized it was important to establish a settlement promptly in order for BPA to be able to incorporate the benefits of the settlement in BPA's rates through its CRACs. If this were not done promptly, BPA's rates might not reflect a reduction for much of the remaining FY 2002-2006 rate period. BPA's GRSPs note that the Administrator can only implement a rate reduction in certain circumstances:

> The SN CRAC parameters and the Thresholds for the FB CRAC and the Rebate will be recalculated if the Administrator, in his sole determination, receives *sufficient assurance*, such as the signing by the IOUs of settlement contracts, that the benefits payable to the IOUs during 2004 through 2006 will be either reduced or deferred. The method by which such benefit reductions will be incorporated depends on the timing of the agreement.

(Emphasis added.) One way to receive "sufficient assurance" is to provide that any litigation settlement be final, and no petitions challenging the litigation settlement be filed within 90 days. *See* 16 U.S.C. § 839f(e)(5). This is addressed in the "Effectiveness" section of the Stipulation, as described below.

C. Stipulation And Agreement For Settlement

The Stipulation and Agreement for Settlement ("Stipulation") is the central document of the litigation settlement. Two additional documents are also particularly important for the settlement. These documents are the amendments to the IOUs REP Settlement Agreements and the Slice Settlement Agreements. These will be discussed in subsequent chapters. The Stipulation contains the following provisions. These provisions have been summarized and parties should refer to the Stipulation itself for the governing language.

1. Effectiveness. The Stipulation provides that it will take effect and be binding when BPA executes the Stipulation and at least one IOU and one public preference utility that is a petitioner in the pending litigation also execute and deliver the Stipulation to BPA, which constitutes the Effective Date. The Stipulation takes effect and is binding as of the Effective Date for each other entity that executes and delivers the Stipulation to BPA. Any entity executing and delivering the Stipulation agrees that the obligations and terms of the agreements are retroactive to the Effective Date. BPA has determined it will have "sufficient assurance" when public litigants and BPA have decided not to withdraw from the Stipulation pursuant to provisions in the Stipulation described below.

2. Amendments to Existing Settlement Agreements. As noted above, BPA and the IOUs have previously entered into a number of agreements regarding settlement of rights and obligations under the REP. In order to ensure consistency among the different agreements, the Stipulation requires BPA and the IOUs to execute and deliver contract amendments contemporaneously with the execution and delivery of the Stipulation. These documents are effective and binding from the Effective Date unless rendered void pursuant to Section 11 of the Stipulation (discussed below) before the 121st day after the Effective Date.

3. Slice Settlement Agreements. BPA's sales of the Slice product are based on a percentage of Federal system power output and service and sold at a rate based on the costs of the system with certain specific costs excluded. Due to the distinct difference in which the Slice contracts sell power and rates have been designed to recover BPA costs, additional steps are necessary in order to ensure that Slice Customers will receive rate benefits from a litigation settlement in the current rate period, and be obligated to repay deferred IOU benefits in the FY 2007-11 period. The settlement does this without in any way altering the Slice Agreement, Slice Rate, or Slice Rate Methodology. Contemporaneously with BPA's execution of the Stipulation, the Stipulation provides that BPA will offer to each Slice Settlement Agreement Party a Slice Settlement Agreement executed by BPA. These documents, upon execution and delivery by the parties, are effective and binding from the Effective Date unless rendered void pursuant to Section 11 of the Stipulation (discussed below) before the 121st day after the Effective Date. The Slice Settlement Agreements are addressed in greater detail in a separate chapter below.

4. Stipulation of BPA Related to Monetary Payments. When BPA develops contracts and rates, BPA must comply with all statutory and regulatory requirements. In the Stipulation, BPA agrees that the calculation of monetary payments, and the payments themselves, under the Amended Settlement Agreements are neither a rate nor a sale of power as those terms are used in the Pacific Northwest Electric Power and Conservation Act.

5. Record of Decision. The Stipulation acknowledges that this ROD will state that the IOUs' monetary payments do not constitute a rate or sale of power under the Pacific Northwest Electric Power and Conservation Act. After reviewing this language, the DSIs expressed a ratemaking concern regarding the allocation of costs resulting from a trigger of the section 7(b)(2) rate test. This concern is that, in the future, the DSIs would be allocated all the costs of a section 7(b)(2) trigger. BPA notes that it cannot decide ratemaking issues outside a section 7(i) hearing, and that the conduct of the section 7(b)(2) rate test and the allocation of costs under section 7(b)(3) will only be decided in such a hearing. However, the DSIs' concern was not created by the current settlement. Under the initial REP Settlement Agreements, BPA had the option to provide either power or monetary benefits to the IOUs for FY 2007-11. Providing all monetary benefits under the current settlement is thus the same as under the initial REP Settlement Agreements. Furthermore, even if BPA had chosen to provide power to the IOUs under the initial agreements, such power sales may be subject to allocation of any 7(b)(2) trigger amount (although BPA has not yet addressed this issue). In the event this occurs, with the result that the RL rate is higher than the PF Preference rate, the IOUs had the option under the initial agreements to convert their power sales to monetary benefits, thereby, once again, receiving all monetary benefits as provided in the current settlement.

In addition, BPA notes that the costs of the 7(b)(2) trigger are not allocated only to DSI loads, but also to Residential Exchange loads. While the IOUs have settled their Residential Exchange rights and obligations, public agency customers have not done so. This means that Residential Exchange loads would likely still exist and be allocated costs from a 7(b)(2) trigger. Furthermore, BPA develops rates using a particular sequence of rate design steps. In other words, BPA has implemented the provisions of section 7(c)(2) of the Northwest Power Act (which provides in simple terms that the IP rate is based on the PF Preference rate plus a margin) both prior to the conduct of the 7(b)(2) rate test and after the 7(b)(2) rate test. The IP rate is thus allocated the costs of a 7(b)(2) trigger but is also established based on the PF Preference rate plus a margin. BPA will be working with the region to address the issue of power sales to the DSIs for the post-2006 period. BPA expects the DSIs to advocate contract provisions that would allow the DSIs to curtail load without penalty in the event that the allocation of costs from the 7(b)(2) rate test made operations uneconomic.

The Stipulation also acknowledges that this ROD will state that the offering and execution of the Slice Settlement Agreement does not constitute a change or modification to the Slice Rate, the Slice Rate Methodology or the Slice Agreement. These statements are set forth in Section II of this ROD. In the event that the Stipulation and Settlement Documents are rendered void pursuant to Section 11 of the Stipulation, this Record of Decision will be rendered moot and withdrawn by BPA and it will not be used subsequent to such withdrawal as the basis or justification for any BPA action.

6. Adjustments to FY 2004 SN CRAC Percentage Increase. The Stipulation provides that if it is in effect on the 121st day after the Effective Date, BPA will implement a reduction to BPA's FY 2004 wholesale power rates subject to the SN CRAC and will provide a rate rebate that is described in an attachment to the Stipulation. The attachment describes how the Administrator can ensure that customers receive the benefit of the settlement in FY 2004, even if the final agreement on settlement is reached after September 15, 2003. In summary, on October 1, 2003, BPA will begin charging customers subject to the FB and SN CRACs the "Without Settlement FB and SN CRAC" rates as presented at BPA's August 28, 2003, rate case workshop. Once the Administrator receives sufficient assurance that there is a final settlement, the Administrator will rebate to customers the difference between the "Without Settlement" rates and the "With Settlement" rates, *i.e.*, the Rebate Amount, as described below. The "With Settlement" rates will result in FY 2004 BPA power rates about 7 percent lower than average FY 2003 rates.

The Administrator was confident enough that there would be a settlement to describe how he would implement the GRSPs once he has sufficient assurance that there is, in fact, a settlement. The Administrator will not reduce the SN CRAC until he has sufficient assurance of a settlement. Sufficient Assurance will occur once the settlement is final and the revenue requirement reductions associated with the settlement are contractually binding (necessary parties have signed and the IOUs make final decisions after the time for challenges has passed). BPA anticipates this will occur sometime in February 2004, in which event rate rebates as described above will be provided. If a final settlement is not secured until after then, the Administrator retains the discretion to provide credits in FY 2005 rather than wait until FY 2006.

The 2003 SN CRAC provides for a recalculation of the SN CRAC parameters and thresholds contingent on changes in data inputs. One of the contingencies is the negotiated reduction in the magnitude of benefit payments by BPA to the IOUs under the 5(c) Settlement Agreements. The GRSPs contemplate a negotiated reduction and provide further that "if the Administrator, in his sole determination, receives sufficient assurance, such as the signing by the IOUs of settlement contracts, that the benefits payable to the IOUs during FY 2004 through FY 2006 will be either reduced or deferred," then the SN CRAC parameters and thresholds will be recalculated, thereby reducing the level of the SN CRAC. *2003 Safety Net Cost Recovery Adjustment Clause Final Proposal, Administrator's Record of Decision*, SN-03-A-02, Appendix A, Page A-17.

The Administrator determined that he would have sufficient assurance of a negotiated reduction in benefits under the IOU agreements if there is a binding agreement by the IOUs to defer $75 million in FY 2004, FY 2005, and FY 2006 plus all but Portland General Electric's share of the $55 million FY 2003 deferral amounts, 120 days after the Effective Date of the settlement contracts deferring the benefits.

The GRSPs state "[t]he method by which such benefit reductions will be incorporated depends on the timing of the agreement." *Id*. The GRSPs acknowledge a settlement deferring or reducing IOU benefits could be achieved in time to implement a SN and/or FB CRAC rate reduction before the rate period begins on October 1, 2003. While the GRSPs contemplated "the agreement" as a signed, final agreement; they do not directly address the situation of an agreement in principle. While BPA does not now have a signed, final settlement agreement, it would appear that the parties are very close to a signed, final agreement. Given this situation, and BPA's intent to promote settlement sooner rather than later and to provide customers the benefit of a "final" settlement if it is reached early on in FY 2004, it is reasonable to provide for a rebate process in FY 2004.

In order to pass on the savings of a settlement for public customers (non-Slice Products), DSIs, IOU power sales, and IOU Monetary Benefits, beginning October 1, 2003, BPA will charge the base rate plus the appropriate Cost Recovery Adjustment Clauses (LB, FB, or SN CRACs) at the levels described at the June 10, 2003, workshop for LB CRAC and the August 28th workshop for SN and FB CRACs.

With settlement, the SN CRAC will go to zero percent for FY 2004. The FB CRAC may be different once the exact settlement amounts are known. Currently, BPA expects the FB CRAC to change by less than one-half of a percent, if at all, from the level presented in the August 28th workshop. The following is a short discussion of how the calculation will be done consistent with the GRSPs. BPA may conduct another workshop as soon as practicable to explain the actual calculation, probably sometime in February.

If the Administrator receives Sufficient Assurance of a settlement, BPA will calculate new FB and SN CRAC parameters. The "contingent recalculation" described in the

August 14 and August 28 workshops for the Without Settlement case will be performed for the With Settlement numbers. Data from the Final Rate Case Studies will be used except for defined updates (chiefly 2003 hydro and price data, and settlement details). The results will be revised caps for the SN CRAC and revised thresholds for both the FB and SN CRACs.

1. Preliminary calculation of FB and SN rates for FY 2004. The revised caps and thresholds for FY 2004 and the FY 2003 Third Quarter Review projections of PBL ending Accumulated Net Revenues (ANR) will be used to calculate the FB CRAC percentages and preliminary percentages for SN CRAC for FY 2004.
2. Administrator exercises GRSP discretion. The Administrator then will exercise the discretion given him in the GRSPs to reduce the FY 2004 SN CRAC to zero percent.
3. Recalibrate FY 2005 and FY 2006 CRACs to maintain three-year 80 percent TPP. The thresholds for the FY 2005 and FY 2006 FB and SN CRACs will be recalibrated, taking into account the zero percent SN CRAC for FY 2004, to maintain a three-year 80 percent TPP (FY 2004 through FY 2006). This step will not affect any FY 2004 FB or SN CRAC thresholds or percentages.

For the FB and SN CRACs, the total difference between what a customer is being billed at the Without Settlement FB and SN CRAC rates and what they would have been billed at the With Settlement SN and FB CRACs rates (the "Rebate Amount") will be calculated for each billing month.

On the first day of the billing month following the date of Sufficient Assurance (assumed to be February 1, 2004) the Rebate Amount will be credited to the customers on a rolling month-by-month basis. For example, in February, the January bill will be calculated using the With Settlement FB and SN CRAC Rates and the October bill will be revised to credit the October Rebate Amount. The next month, March, the process would be repeated, with the February bill being calculated using the With Settlement Rates and the November bill being revised to reflect the Rebate Amount; and so on. Revised bills and Rebate Amounts will only be calculated for whole months. If the date of Sufficient Assurance occurs in February 2004, but after February 1, the Rebate Amount for October will not be credited until the March calculation of the February power bills.

7. BPA Contractual Commitments. The Stipulation provides that BPA will not include in any power sales, load reduction or power buy-back agreement a provision to pay additional money to or decrease the amounts paid by the customer under any such agreement that is expressly contingent upon another customer, that is not a party to any such agreement, exercising or continuing to exercise its right to judicially challenge a BPA action. This, however, does not preclude BPA from otherwise adjusting the price or compensation in an agreement with a customer for risks incurred in the conduct of business with BPA.

8. BPA Principles for Settlement.

(a) Future SN CRAC Adjustments. The BPA Administrator has the objectives of keeping rates as low as reasonably possible, and achieving a zero SN CRAC rate adjustment for FY 2005, while assuring BPA cost recovery and a sufficiently high U.S. Treasury repayment probability. In order to position the Administrator so that he will most likely be able to exercise the discretion available to him under the SN-03 CRAC GRSPs (SN-03-A-02, as corrected by errata) to reduce the SN CRAC rate adjustment to zero for FY 2005, the Administrator: (i) has identified an aggregate cost reduction and revenue increase target of approximately $100 million that in the Administrator's estimation would, if achieved over FY 2004 and FY 2005 and all other costs and revenues remained at the level forecast in the third quarter review for FY 2003, allow for a zero SN CRAC rate adjustment for FY 2005; and (ii) will work with customers and other third parties, through a public process, to achieve those aggregate cost reductions and revenue enhancements (other than rate increase and secondary revenue performance), as the Administrator determines is appropriate.

(b) Cost Reductions and Revenue Improvements. BPA will conduct an open and collaborative public process, which will focus on achievement of the cost reduction and revenue improvement target, and on a schedule that will permit information regarding cost reductions and revenue enhancements to be considered in BPA's FY 2005 SN CRAC decision. This process will involve BPA, customers, and other interested parties. Key features of this process include: (i) periodic sharing (at least quarterly) by BPA of pertinent information on actions taken and actions planned to achieve the cost reduction and revenue improvement targets, and reporting of actual progress toward the target; (ii) collaborative and ongoing consultations between BPA, customers, and other parties on how best to achieve the cost reduction and revenue improvement target; (iii) the intent to use outside expertise to define opportunities for process improvement; (iv) the SN-03 CRAC GRSPs (SN-03-A-02, as corrected by errata) allow the Administrator to elect at his discretion to reduce the SN CRAC rate adjustment for a fiscal year, and provide that if the Administrator elects to reduce the SN CRAC rate adjustment, BPA will recalibrate the caps for the SN CRAC and the thresholds for FB CRAC and SN CRAC for later years to maintain the equivalent of the three year TPP of 80 percent (calculated as 80 percent for three years, 86.2 percent for two years, and 92.8 percent for one year). As a part of the Administrator's decision for FY 2005 and then again for FY 2006 whether to reduce the SN CRAC rate adjustments, and acting consistent with the GRSPs, the Administrator commits to calculating a forward looking TPP for the remainder of the rate period using the BPA Toolkit, and to incorporating into that analysis changes in costs and revenues forecast by the Administrator. If the TPP is above the target levels, the Administrator will give due consideration to using his discretion to reduce the SN CRAC percentage, with the goal of achieving a zero percent SN CRAC; (v) sharing by BPA of draft forecasts, assumptions and the Toolkit model used in the calculation of forward-looking TPP for FY 2005 and FY 2006, and ample opportunity for input used in those forecasts and assumptions, not less than 60 days in advance of the FY 2005 and FY 2006 SN CRAC decisions (this is in addition to the information requirements in the SN CRAC GRSPs, but does not require BPA to use the draft information in BPA's final calculations, because the information may change between when it is made available and BPA's final calculations). Any sharing of information shall be limited to the extent it involves materials covered under section 8(c); (vi) opportunities for collaborative discussions with the Administrator regarding the appropriate exercise of the Administrator's discretion in setting the level of the FY 2005 and FY 2006 SN CRACs. The Administrator will give due consideration to the comments made at such collaborative discussions when setting the levels of such SN CRACs in accordance with the SN CRAC GRSPs.

Not later than 30 days after the Effective Date, the Administrator will convene discussions with customer representatives and other parties for the purpose of establishing the specifics of this process. The objective will be to define the process not later than 90 days after the Effective Date.

(c) Privileged Information. The BPA Administrator reserves the discretion when sharing forecasts, pertinent information, or assumptions to not include information BPA determines to be privileged or exempt from disclosure under FOIA including any material BPA determines to be proprietary and business sensitive.

(d) Failure to Achieve Objectives of These Principles. The target for cost reductions and revenue enhancements described in sections 8(a) and 8(b) of the Stipulation is just that: a target. The failure or inability of the Administrator to achieve the target or take aggressive or sufficient actions to achieve it or provide a particular process has no legal consequence under the Stipulation, and shall gives rise to no remedies in law or equity for breach of the Stipulation. The Parties recognize that even if the target is achieved, low water or adverse events could partially or totally offset the cost reductions or revenue enhancements. Conversely, high water, favorable market conditions, or other positive events when considered in the forward forecast may improve the Administrator's ability to exercise discretion in determining the size of any FB CRAC or SN CRAC.

9. Waiver and Covenant Not to Sue; Other Challenges.

(a) Waiver and Covenant Not to Sue by Party. Each Party is required to execute and deliver to BPA in trust a Waiver and Covenant Not to Sue contemporaneously with the execution and delivery of the Stipulation. The Waivers and Covenants Not to Sue are incorporated in the Stipulation by reference.

(b) Covenants Not to Sue by Non-Party. Any person or entity that is not a Party may, before the 90th day after the Effective Date, execute and deliver to BPA in trust a Waiver and Covenant Not to Sue.

(c) Filing or Return of Waiver and Covenant Not to Sue. If the Stipulation has not been voided *ab initio* pursuant to section 11 before the 121st day after the Effective Date, BPA will file and serve each Waiver and Covenant Not to Sue along with each Motion to Dismiss filed and served pursuant to section 10(c) of the Stipulation. If the Stipulation has been voided *ab initio* pursuant to section 11 before the 121st day after the Effective Date, BPA will, on or before the 125th day after the Effective Date, return each of the originally signed Waivers and Covenants Not to Sue to the respective signing Parties, persons or entities.

(d) Other Challenges. Except to the extent inconsistent with the Waiver and Covenant Not to Sue executed and delivered by a Party pursuant to section 9(a) of the Stipulation, each Party is free to exercise whatever rights it may have under law to petition for review, or otherwise lawfully challenge, the Administrator's triggering of and implementation of the SN CRAC.

(e) Release of Claims by Investor-Owned Utilities Against Direct Service Industrial Customers. Each Party that is an IOU agrees in the Stipulation to release any and all claims it may have to challenge BPA's power sales (or rates) for service to BPA's direct service industrial customers for the fiscal year (FY) 2002-2006 period. Because the IOUs have waived all challenges to the power sales and rates to the DSIs for the noted period, the DSIs are contractually required by their Compromise Approach Agreements and their Subscription Block Power Sales Agreements with BPA to waive all challenges to the IOUs' Subscription power sales and rates.

10. Motions to Dismiss.

(a) Motions to Dismiss Certain Rate Claims.

(i) Party. The Stipulation permits Parties to timely file petitions for review regarding BPA's WP-02 rates (or any CRAC during the WP-02 rate period). Any Party that has, however, as of its execution and delivery of the Stipulation, filed such a petition or motion is required to, contemporaneously with its execution and delivery of the Stipulation, execute and deliver to BPA in trust a Motion to Dismiss Certain Rate Claims captioned to include all Cause Numbers as to which the Party has filed such a petition or motion. Any Party that, after its execution and delivery of the Stipulation, files such a petition or motion is required to exclude from such petition or motion any claims precluded by the Waiver and Covenant Not to Sue executed by the Party. The Party is required to, not later than the 90th day after the Effective Date, execute and deliver to BPA in trust a Motion to Dismiss Certain Rate Claims captioned to include all Cause Numbers as to which the Party has filed a petition or motion.

(ii) Non-Party. Any person or entity that is not a Party but that files or has filed a petition for review or motion to intervene in the Ninth Circuit on any issue regarding BPA's WP-02 rates (or any CRAC during the WP-02 rate period) may, before the 90th day after the Effective Date, execute and deliver to BPA in trust a Motion to Dismiss Certain Rate Claims captioned to include all Cause Numbers as to which such person or entity files or has filed such a petition or motion.

(b) Motions to Dismiss Causes and Claims. Each Party that has filed, as of its execution and delivery of the Stipulation, a petition or motion to intervene in any of the Referenced Causes (which are listed in the Stipulation) is required to contemporaneously with its execution and delivery of the Stipulation execute and deliver to BPA in trust a Motion to Dismiss Causes and Claims.

(c) Filing or Return of Motions to Dismiss. If the Stipulation has not been voided *ab initio* pursuant to Section 11 before the 121st day after the Effective Date, BPA is required to file and serve each Motion to Dismiss. If the Stipulation has been voided *ab initio* pursuant to section 11 before the 121st day after the Effective Date, BPA is required to, on or before the 125th day after the Effective Date, return each of the originally signed Motions to Dismiss to the respective signing Parties, person or entity.

(d) Severance of Reserved Claims; Stipulation and Agreement to Dismiss. All of the Parties agree to the dismissal (with prejudice and with each party to bear its own costs) of all petitions and claims in each of the Referenced Causes, other than Cause No. 00-70948. The Parties also agree to the severance of Cause No. 00-70948 from each of the other Referenced Causes.

The Parties also represent to each other that the Referenced Causes encompass all pending litigation known to such representing Parties that challenge or may challenge BPA's Slice Agreements, Residential Exchange Program, Residential Purchase and Sale Agreements, or any of the Existing Settlement Agreements or Amended Settlement Agreements.

(e) Administrator's Authority. The Stipulation provides that it, and actions taken pursuant to it, are not intended in any way to alter the Administrator's authority to review periodically and revise the Administrator's power and transmission rates in a manner not inconsistent with this Stipulation so that BPA's rates meet statutory requirements, including but not limited to any requirement that the Administrator's power and transmission rates recover costs and assure repayment of the United States Treasury.

11. Voiding of Stipulation and Events Of Default.

The Stipulation describes two sets of circumstances regarding the viability of the Stipulation. One set of circumstances immediately renders the Stipulation void. Another set of circumstances, events of default, permits parties to withdraw from the Stipulation.

(a) Voiding of Stipulation. The Stipulation and all other Settlement Documents are void *ab initio* upon the occurrence of any of the following events: (i) *Failure to Execute and Deliver.* Failure of any Public Litigant to execute and deliver to BPA in trust, on or before the 90th day after the Effective Date, each of the following: (A) a Waiver and Covenant Not to Sue; (B) a Motion to Dismiss Causes and Claims; and (C) a Motion to Dismiss Certain Rate Claims; (ii) *Withdrawal from Stipulation.* Withdrawal, pursuant to an Event of Default, from the Stipulation by any Public Litigant or BPA; (iii) *Court Action Prior to 121st Day.* Withdrawal by any party, pursuant to an

Event of Default described in item (iii), (iv), or (viii) of Section 11(b). If the Stipulation and all other Settlement Documents are void *ab initio* under Section 11, BPA will withdraw this Record of Decision and such ROD will be void *ab initio*.

(b) Events of Default. The occurrence of any of the following events constitutes an Event of Default: (i) *Failure of Other Litigant to Execute and Deliver***.** Failure by any Other Litigant in the Referenced Causes that is not a Party to the Stipulation to execute and deliver to BPA in trust each of the following: (A) the Waiver and Covenant Not to Sue; (B) a Motion to Dismiss Causes and Claims; and (C) a Motion to Dismiss Certain Rate Claims; (ii) *Failure of the Investor-Owned Utilities to Execute and Deliver.* Failure of any IOU to execute and deliver the Stipulation, the Amendment to Existing Settlement Agreement, the Motions to Dismiss, and the Waiver and Covenant Not to Sue; (iii) *Challenges to Settlement.* Filing or maintaining by any person or entity of any claim in the Ninth Circuit (or any other court) that a Party would be precluded from filing or maintaining by its Waiver and Covenant Not to Sue, including a challenge to any of the following actions: offering or entering into the Stipulation, offering or entering into any Amendment to Existing Settlement Agreement, offering or entering into any Slice Settlement Agreement, issuance of the final Record of Decision, filing or joining the Motions to Dismiss, or any action proposed or taken by the Administrator required or contemplated by this Stipulation or other Settlement Documents; (iv) *Failure to Dismiss Rate Claims***.** Failure by any person or entity, whether or not a Party, that has filed a petition for review or intervened in any proceeding regarding BPA's WP-02 rates (or any CRAC during the WP-02 rate period) to execute and deliver to BPA in trust a Motion to Dismiss Cetain Rate Claims, if such person or entity has as of the 90th day after the Effective Date filed a petition for review or motion to intervene in the U.S. Court of Appeals for the Ninth Circuit or the Federal Energy Regulatory Commission that includes or may include any claim that a Party would be precluded from filing or maintaining by its Waiver and Covenant Not to Sue regarding BPA's WP-02 rates (or any CRAC during the WP-02 rate period); (v) *Withdrawal of Investor Owned Utility(s) from Stipulation.* Withdrawal, pursuant to an Event of Default, from the Stipulation by any IOU; (vi) *Agreed-to Annual Deferral Amounts of Less Than $75 Million.* The IOUs fail to enter into Amendments to Existing Settlement Agreements specifying Annual Deferral Amounts in the appropriate exhibits to their respective Amended Settlement Agreements in an aggregate amount of $75 million per year for FY 2004, 2005 and 2006 (this amount does not include the $55 million of deferrals previously agreed to for FY 2003); (vii) *Failure of Slice Customer to Execute Slice Settlement Agreement.* Any Slice Settlement Agreement Party fails to execute and deliver a Slice Settlement Agreement; or (viii) *Court Action Prior to 121st Day***.** The Stipulation or any other Settlement Document is, prior to the 121st day after the Effective Date, enjoined, stayed, or determined to be void, unenforceable, or unlawful.

If an Event of Default has occurred and is then continuing, any Party including BPA (other than an entity whose action gave rise to such Event of Default) may withdraw from the Stipulation by serving timely notice upon the General Counsel of Bonneville Power Administration, (A) not earlier than the 90th day after the Effective Date and not later than the 105th day after the Effective Date in the case of withdrawal by any IOU, and (B) not earlier than the 106th day after the Effective Date and not later than the 120th day after the Effective Date in the case of withdrawal by any other Party; provided, that no Party other than BPA may withdraw due to an Event of Default described in item (vi) or (vii) above; provided further, any Party may withdraw due to an Event of Default described in item (iii), (iv), or (viii) above at any time after the 90th day after the Effective Date but not later than the 120th day after the Effective Date. Such withdrawal from the Stipulation is irrevocable. Any Party that withdraws from the Stipulation pursuant to Events of Default will be deemed to have executed neither the Stipulation nor any other Settlement Documents. BPA will promptly return to such Party its executed Settlement Documents.

12. Survival of Settlement Documents. If the Stipulation has not been voided *ab initio* pursuant to Section 11 before the 121st day after the Effective Date, (a) the Amendments to Existing Settlement Agreements, which among other things provide for amendment of the Existing Settlement Agreements to, in effect, provide for the continuation of the Reduction of Risk Discount through September 30, 2006, will be independent of all other Settlement Documents and will remain in effect even if any or all other Settlement Documents are void, unenforceable or unlawful; and (b) the Waivers and Covenants Not to Sue will be independent of all other Settlement Documents and will remain in effect even if any or all other Settlement Documents are void, unenforceable or unlawful.

13. Scope of Stipulation.

(a) Entirety of Agreement; Attachments Incorporated. The Stipulation contains the entirety of the Parties' agreement with respect to the subject matter of the Stipulation. The Stipulation includes the body of the document and the following Attachments, which are incorporated therein by reference: (i) ATTACHMENT A—Definitions; (ii) ATTACHMENT B—Petitioners and Intervenors in Referenced Causes; (iii) ATTACHMENT C—Service List; (iv) ATTACHMENT D— Form of Waiver and Covenant Not to Sue; (v) ATTACHMENT E—Form of Motion to Dismiss Causes and Claims; (vi) ATTACHMENT F—Form of Motion to Dismiss Certain Rate Claims; and (vii) ATTACHMENT G— September 18th SN CRAC Workshop Materials.

(b) Other Attachments Not Incorporated. The following forms of Amendment to Existing Settlement Agreement and Slice Settlement Agreement are attached for reference but are not incorporated in the Stipulation: (i) Form of Amendment No. 1 to Contract No. 01PB-10885 between BPA and Puget; (ii) Form of Amendment No. 2 to Contract No. 01PB-12229 between BPA and PacifiCorp; (iii) Form of Amendment No. 2 to Contract No. 00PB-12161 between BPA and PGE; (iv) Form of Amendment No. 3 to Contract No. 00PB-12157 between BPA and Avista; (v) Form of Amendment No. 3 to Contract No. 00PB-12158 between BPA and Idaho Power Company; (vi) Form of Amendment No. 3 to Contract No. 00PB-12160 between BPA and NorthWestern Energy; (vii) Form of Amendment No. 1 to Contract No. 01PB-10854 between BPA and PacifiCorp; (viii) Form of Slice Settlement Agreement for each Slice Settlement Agreement Party.

14. Notices.

(a) Notice of Final Action. The Administrator will promptly provide general notice to the public utilizing the BPA website and the mailing list for BPA's *Journal* publication that, as of the Effective Date, the Administrator is (i) offering and executing the Stipulation, (ii) offering and executing the Amendments to Existing Settlement Agreements, (iii) offering and executing the Slice Settlement Agreements, (iv) executing the Waiver and Covenant Not to Sue, and (v) issuing the final Record of Decision.

(b) Notice Requirements for Certain Events. Promptly upon BPA's knowledge of the occurrence of any of the following events, BPA will notify by electronic mail (or facsimile if electronic mail is not available) and by posting on BPA's website each Party that has then entered into the Stipulation, each IOU, each Public Litigant, and each Other Litigant of the occurrence and date of such event: (i) the Effective Date; (ii) the occurrence of any event voiding *ab initio* the Stipulation; (iii) the occurrence of any Event of Default or withdrawal from the Stipulation; (iv) the execution and delivery to BPA of the Stipulation, each Motion to Dismiss by any entity; (v) the execution and delivery to BPA of each Slice Settlement Agreement, each Amendment to Existing Settlement Agreement, and each Waiver and Covenant Not to Sue by any entity; and (vi) receipt by BPA of any petition for review challenging the WP-02 rates (or any CRAC during the WP-02 rate period) or the Stipulation or any other Settlement Document (or motion to intervene with respect to any such petition). Notice will be delivered by BPA to each person or persons listed in a Service List attached to the Stipulation.

(c) Delivery of Executed Settlement Documents and Motions to Dismiss. Any Party may effect delivery of its executed Settlement Documents, and any person or entity may effect delivery of its Motion to Dismiss, to BPA by any of the means for giving notice to BPA. If the Stipulation has not been voided *ab initio* pursuant to section 11 before the 121st day after the Effective Date, BPA will, on or about the 125th day after the Effective Date, deliver to each Party a copy of all Settlement Documents, including all signature pages, as executed and delivered to BPA.

(d) Other Notices. Except as provided in Section 14(b) above, any notice, demand, approval, consent, waiver, direction, or request required or permitted under the terms of the Stipulation will be in writing and (i) delivered personally, (ii) sent by registered mail, with return receipt requested, (iii) sent by recognized overnight mail or courier service, with delivery receipt requested, or (iv) sent by telecopier or facsimile. Notices to BPA shall be delivered to BPA's Office of General Council at the address contained in the Stipulation. Notices to Parties other than BPA will be provided to the person or persons listed in the Service List attached to the Stipulation. Notices will be effective from the date received by the intended recipient Party. Any Party may change its designation on the Service List by giving notice to all other Parties in the manner provided in the Stipulation.

15-18. General Provisions. Sections 15 through 18 of the Stipulation address provisions that are typically included in BPA's contracts. These provisions include representations of authority, the parties bound, construction of the Stipulation, and execution in counterparts.

19. Savings Clause.

(a) No Precedent. The Parties agree that no action taken or not taken by any Party, person or entity with respect to the Stipulation, any other Settlement Document, or the Record of Decision will serve to create any procedural or substantive precedent with respect to BPA's service after September 30, 2011, in (i) any subsequent administrative forum, or (ii) any subsequent administrative, arbitral, or judicial forum reviewing BPA's decisions; nor will any Party argue otherwise. No record of decision (nor any action taken or not taken by any Party, person or entity) with respect to any claim in the Referenced Causes, nor any claim with respect to such a record of decision in other causes dismissed pursuant to any Motion to Dismiss Certain Rate Claims or Motion to Dismiss Causes and Claims, will serve to create any procedural or substantive precedent with respect to BPA's service after September 30, 2011, in (i) any subsequent administrative forum, or (ii) any subsequent administrative, arbitral, or judicial forum reviewing BPA's decisions; nor will any Party argue otherwise. The Parties acknowledge that certain Parties, persons or entities have opposing positions on certain issues. In addition, nothing in this Stipulation will be construed or deemed to be an admission, or evidence of an admission, by any Party with respect to any claim dismissed pursuant to any of the Motions to Dismiss Certain Rate Claims and Motions to Dismiss Causes and Claims or with respect to any of the Reserved Claims.

(b) Return of Documents. If the Stipulation has been voided *ab initio* pursuant to section 11 before the 121st day after the Effective Date, BPA will return to each Party the Stipulation and all other Settlement Documents as executed by such Party by the 135th day after the Effective Date.

D. AMENDMENTS TO IOU SETTLEMENT AGREEMENTS

1. Amendments Generally

In addition to the Stipulation, the IOUs' Amendments to Settlement Agreements (Amendments) are new contractual agreements needed to implement the Stipulation which, as the name implies, amend the IOUs' previous REP Settlement Agreements. The Amendments are offered to each IOU (PacifiCorp, due to the structure of its previous agreements, is offered two amendments). The Amendments amend, among other things, provisions regarding the additional deferral of Monetary Benefits during Fiscal Years 2004, 2005, and 2006, and the payment of Monetary Benefits during the period that begins on October 1, 2006, and continues through September 30, 2011. Further, the Amendments terminate the IOUs' Agreements Regarding Fiscal Year 2003 Deferral Amount with BPA. The Amendments with PacifiCorp and Puget in effect provide for the continuation of the Reduction of Risk Discount through September 30, 2006, terminate their Conditional Deferral Agreements, and eliminate the obligation of BPA to pay all deferred amounts of benefits under the Conditional Deferral Agreements. The Amendments also eliminate the possibility of BPA making actual power deliveries to the IOUs in the FY 2007-2011 period, and limit the IOU benefits to monetary payments. The Amendments are entered into in consideration of the Stipulation executed by the IOUs contemporaneously with the Amendments.

The Amendments are effective on the Effective Date defined in the Stipulation, unless voided under the contract provisions specified above. The Amendments amend the REP Settlement Agreements, among other things, with regard to the benefits provided to the IOUs. As noted previously, revision of benefits provided to the IOUs can provide BPA with a means to lower its revenue requirement and, through the CRACs, lower BPA's wholesale power rates. The revision of the IOUs' benefits takes two forms: (1) deferrals of benefit payments, and (2) adjustment of a component of the formula for calculating monetary benefits.

2. Deferrals.

The parties agreed that the IOUs and BPA adopt deferrals of benefit payments from the current rate period to FY 2007-11. This is accomplished through the amendment of the IOUs' Settlement Agreements and the termination of the IOUs' "Agreements Regarding Fiscal Year 2003 Deferral Amount." The amount of the total deferral is $280 million, comprised of the existing $55 million of deferrals from FY 2003 and $75 million from each of FYs 2004, 2005, and 2006. The sum of the Annual Deferral Amounts for Contract Years 2003 through 2006 determined for each IOU will be paid, plus interest, to each respective IOU. BPA will pay this sum in addition to paying each month any amounts otherwise due to be paid to the IOU pursuant to the provisions of the Settlement Agreement for FY 2007-11. All of the IOUs except PGE have agreed to relinquish their rights to use the FY 2003 deferral amount to offset reductions in their settlement benefits due to BPA's imposition of an SN CRAC. The deferral amount for FY 2004, 2005 and 2006 and the FY 2003 deferral amounts for all IOUs except PGE will be paid by BPA to the IOU in 60 equal monthly installments during the period October 1, 2006, through September 30, 2011. PGE's FY 2003 deferral amount will be repaid during FY 2005 and 2006 to the extent BPA imposes an SN CRAC and reduces PGE's settlement benefits. Any amounts not repaid to PGE during FY 2005 and 2006 will be repaid in the same manner as other deferrals (unless earlier repayment is required).

As provided in section 6 of the Amended Settlement Agreements, benefits will be passed through to residential and small farm consumers consistent with procedures developed by the governing state regulatory authority. Benefits are identified on each IOU's books of account and are held in an interest bearing account and maintained as restricted funds unavailable for the operating or working capital needs of the IOU. Benefits also cannot be pooled with other IOU funds for investment purposes. The amendment increases the amount of benefits allowed to be held in the account described in section 6. This amount cannot exceed an amount equal to the greater of: (1) the expected receipts of monetary payments from BPA under the Settlement Agreement over the next 36 months, or (2) the receipts of monetary payments from BPA under the Settlement Agreement over the immediately preceding 36 months; provided, however, that any amount of benefits held in such account must be distributed to the IOU's Residential Load no later than April 1, 2012.

The deferral provisions allow BPA to reduce its revenue requirement during the current FY 2002-06 rate period. These reductions are then reflected in BPA's CRACs and result in the reduction of BPA's firm power rates during difficult economic times. The ability to hold greater funds in the section 6 account will provide the IOUs with greater flexibility in the distribution of benefits to residential and small farm consumers in order to avoid rate shock and accomplish the efficient and economical distribution of benefits.

3. Adjustments To '07-'11 Monetary Benefits.

(a) Elimination of Reduction of Risk Payments. As noted previously, section 4(b), footnote 2, of PacifiCorp's Financial Settlement Agreement, Contract No. 01PB-10854, and section 4(b)(1)(B), footnote 2, of Puget's Amended Settlement Agreement, Contract No. 01P-10885, provide that the respective utilities are willing to reduce the amount of benefits received under their agreements. These benefit reductions only occur in the event that the respective utilities have entered into settlement agreements with certain publicly owned utility and cooperative customers that waive and dismiss legal challenges, *inter alia*, to the respective utilities' original REP Settlement Agreements. In order to reduce PacifiCorp's and Puget's benefits, litigation settlements with publicly owned utility and cooperative customers had to occur by December 1, 2001. The amount of the benefit reduction, for PacifiCorp and Puget combined, is approximately $200 million. Absent settlement, the $200 million discount would not be subtracted from their base benefit payment but instead would be paid to PacifiCorp and Puget. These amounts would be included in and recovered through BPA's wholesale power rates. Subsequent deferral agreements deferred the payment of $200 million until notice was provided by PacifiCorp and Puget. The Amendments, based on a settlement of outstanding litigation, would eliminate the payment of the $200 million to PacifiCorp and Puget.

(b) Forward Flat-Block Price Forecast. Monetary benefits in the IOUs' REP Settlement Agreements are determined by a formula, basically, the difference in BPA's rate case Forward Firm-Block Price Forecast and the RL rate (or lowest PF rate in appropriate circumstances) multiplied by the amount of the IOU's benefits as stated in annual aMW. BPA and the IOUs are not eliminating this formula. However, the parties propose a refinement of the determination of the Forward Firm-Block Price Forecast. The Settlement Agreements currently define Forward Firm-Block Price Forecast as "BPA's forecast of the wholesale market price for the purchase of additional amounts of power at 100 percent annual load factor established in the same BPA power rate case as that which established the RL rate and for the period of the RL Rate established in a BPA power rate case Record of Decision (ROD) as finally approved by the Federal Energy Regulatory Commission and affirmed, if appealed, by the United States Court of Appeals for the Ninth Circuit." The amendment establishes a different methodology.

(1) New Methodology. Under the new methodology, BPA hires a qualified third party (QTP). For each Contract Year, the QTP randomly selects 6 to 8 Eligible Data Providers (EDP) separately for each of four consecutive quarters (the first of which commences 21 months prior to the beginning of such Contract Year and the last of which ends 9 months prior to such Contract Year) from the list of EDPs provided to it by a "Committee" comprised of one BPA representative, one PNW IOU representative, and one PNW Public representative. The QTP then surveys the EDPs that have been selected. The QTP asks each selected EDP to provide Forward Price Data for the Contract Year as of a date randomly selected separately for each EDP by the QTP during each such quarter; provided, however, that such date has occurred prior to date of request by the QTP.

Following the completion of each quarterly survey, the QTP excludes the highest and lowest Forward Price Data from the EDPs surveyed during each such quarter. The QTP then calculates the arithmetic mean of the remaining Forward Price Data amounts to determine that quarter's FBPF (the "Quarterly FBPF") for the Contract Year.

Following the completion of the four quarterly surveys, the QTP calculates the arithmetic mean of the four Quarterly FBPFs. The result of this calculation is the FBPF that is used for the Contract Year and the QTP will promptly report the FBPF to the Committee and each regional IOU. Additional details of the methodology are discussed below.

(a) Committee. The Committee members are chosen as follows. The BPA representative is selected by the Vice President, Bulk Marketing & Transmission Services. The PNW Public representative will be selected by the Public Power Council Executive Committee. The PNW IOU representative will be selected by agreement of the PNW IOUs that have executed the Stipulation. If a representative on the Committee is replaced, or if the entity that selects the representative is replaced, then the new representative shall notify the other two representatives in writing of such replacement(s).

If a representative to the Committee has not been selected, the other representatives or representative shall provide written notice to the selecting entity that has not provided a representative of the need to select a representative for the Committee. If such entity does not appoint a representative within 30 days, the existing representatives of the Committee are authorized to act on all matters of the Committee requiring an affirmative vote by each representative on the Committee.

All actions and determinations by the Committee will be by affirmative vote of each representative on the Committee.

(b) QTP. The QTP is a third party that has extensive expertise in the electric power industry, including experience in auditing FAS 133 compliance and risk accounting for publicly reporting entities in the electric power industry, and is selected by BPA. Prior to the beginning of each Contract Year, BPA selects a QTP from a list of qualified parties submitted to it by the Committee. The list compiled by the Committee includes, at a minimum, the four largest internationally recognized accounting firms, which currently include: KPMG, Deloitte and Touche, Pricewaterhouse Coopers, and Ernst & Young (Big 4 Accounting Firms). Each additional qualified party to be included on such list require an affirmative vote by each representative on the Committee.

BPA consults with the PNW IOU and the PNW Public representatives on the Committee prior to selecting the QTP. The initial QTP selected is retained for the first Contract Year only, with an option to extend for subsequent Contract Years. BPA pays the costs for services provided by the QTP.

If, after consulting with the Committee, BPA determines that the contract for the then-current QTP will not be extended, BPA will, upon advice of the Committee, seek to replace the existing QTP. The Committee consults and decides whether to add additional qualified parties to the list.

Each contract with the QTP includes a requirement that: (1) the QTP maintain the confidentiality of the data collected from the EDPs except for making the data available to a reviewer, (2) the QTP maintain the Forward Price Data it has collected under its contract until September 30, 2011, and (3) the QTP submit, in writing, for resolution by the Committee, any question it may have regarding the determination of the FBPF.

All contracts and communications between BPA and the QTP with respect to the determination of the FBPF will be shared promptly with the Committee and PNW IOUs.

(c) EDP. An EDP (1) routinely buys and sells bulk power for resale in the Pacific Northwest; (2) routinely produces Forward Price Data for use in risk accounting for its financial statements in the normal course of business; (3) is regularly audited by an outside accounting firm; and (4) has been selected by an affirmative vote by each representative on the Committee for inclusion on the list of EDPs and submitted to the QTP. Following the selection of the QTP by BPA, the Committee develops a list of EDPs and submits such list to the QTP. Each EDP included on such list requires an affirmative vote by each representative on the Committee. If possible, such list will contain at least 10 EDPs, and, if possible, each survey by the QTP will include at least two PNW Publics, two PNW Investor-Owned Utilities, and two Marketers. Such list may be modified from time to time to (a) add EDPs that meet the specified criteria, or (b) remove EDPs that no longer satisfy the criteria, as determined by an affirmative vote by each representative on the Committee.

In addition, if any EDP submits Forward Price Data two or more times during any period of four consecutive quarters and more than 50 percent of such submittals by such EDP are excluded as being the highest or lowest Forward Price Data, and the excluded Forward Price Data for any such quarter differs from the quarterly FBPF for such quarter by more than 5 percent, the QTP will, for the next four quarters following such period, not include such EDP in the selection for its surveys.

The new methodology also contains provisions regarding record-keeping, confidentiality, audit, and the inability to obtain information.

(2) Reasons for Revised FBPF. As noted previously, the current means of calculating the FBPF is through BPA's forecast of the wholesale market price for the purchase of additional amounts of power at 100 percent annual load factor as established in the same BPA power rate case as that which established the RL rate and for the period of the RL Rate established in a BPA power rate case ROD as finally approved by the Federal Energy Regulatory Commission and affirmed, if appealed, by the United States Court of Appeals for the Ninth Circuit. IOUs expressed concern that BPA views the IOUs' REP settlement benefits as agency costs and that BPA is frequently under pressure to reduce costs and therefore rates. The IOUs were concerned that such an environment could create the appearance that the Administrator would view the FBPF calculation as a means to reduce IOU benefits. It was suggested that an alternative method of calculating the FBPF should be determined. To achieve this goal, the parties developed the methodology described above. Through this methodology, an independent QTP surveys numerous EDPs in order to obtain forward price data, which is averaged to determine the FBPF. This removes any appearance of opportunity for BPA to establish low or high FBPF rate case forecasts.

(a) Floors and caps. Another feature of the revised calculation of IOU benefits is the establishment of a floor and cap for total IOU benefit payments. Previously, the total amount of IOU benefits could vary greatly from year to year. Such dramatic changes result in wholesale power rate instability for BPA's customers and retail rate instability for the IOUs' consumers. The revised benefit calculation establishes a floor of $100 million of IOU benefits per year, and a cap of $300 million of IOU benefits per year. Through the floor, the IOUs receive certainty of a specified minimum level of benefits. Similarly, through the cap, BPA's other customers receive certainty that IOU benefits will not exceed a specified amount.

4. Additional Features

The Amendments contain numerous other provisions. The Amendments provide that no firm power will be provided by BPA to the IOUs under the Amended Settlement Agreements during the period from October 1, 2006, through September 30, 2011, and as a consequence the Amendments will reduce the loads served by BPA, and thus reduce BPA's need to rely on power from the volatile and unpredictable power market. The Amendments also address the calculation of monetary payments to the IOUs, true-ups to the benefits following rate adjustments, exceptions to use of the RL rate in determining monetary benefits, repayment of deferred benefits, voiding of the Amendments (if the Stipulation becomes void *ab initio* or an IOU withdraws from the Stipulation), and severability. Under the Amendments, the Conservation and Renewables Discount is not affected by the IOU benefit deferrals, repayment of those deferrals, or the caps and floors on IOU benefits.

E. Slice Settlement Agreement

In addition to the Stipulation and the IOUs' Amendments to Settlement Agreements, the Slice Settlement Agreements also are new contractual agreements needed to implement the Stipulation. These Agreements allow Slice purchasers to receive the benefit from the rate reductions occurring as a result of the settlement without revision of the Slice Rate, Slice Rate methodology or the Block and Slice power sales agreements.

1. The Slice Product.

At public customers' request, BPA decided to offer a power product for service to a customer's net requirement load, which included a portion of the excess generation in the BPA system during a year. This product was entitled the "Slice of the System" product and BPA decided to include the product in its 2001 Subscription power sales agreements. BPA's decisions on the product can be found in BPA's Power Subscription Strategy ROD, December 21, 1998, at 81-109; BPA's Slice of the System Product Final Detailed Product Report and Response to Public Comment, August 1999; BPA's Power Products Catalog, April 2000, and BPA's Power Subscription Strategy Supplemental ROD, April 26, 2000, at 29.

The Slice product is a power product based upon a purchaser's annual net firm requirements load that is shaped to BPA's system generation output from the FCRPS, rather than shaped to the Slice purchaser's load. The customer's Slice product is based upon a percentage derived by comparing a customer's net firm regional load to an established annual average Firm Energy Load Carrying Capability for the Federal system at the beginning of the customer's Subscription contract (7070 average annual MWs). This percentage remains fixed for the contract term, but the amount of power received in any year of the contract may vary due to varying water, other Federal system conditions, and changes in net load. The actual amount of power sold under this product includes both the firm power and an amount of surplus power depending upon the amount of generation available during any month. In return, the customer agrees to pay a portion of BPA's costs proportionate to the customer's percentage of its FCRPS power purchase. Rather than pay a set price per MWh for its power, a Slice Customer pays its proportionate share of a set of costs referred to collectively as the Slice Revenue Requirement, as adopted in the WP-02 rate case. *See* Administrator's Final Record of Decision, WP-02-A-02, at 16-1 to 16-45.

The pricing structure of the Slice of the System product is different than other Priority Firm Power Rate products. The Slice Rate paid by Slice customers is based on the costs included in the Slice Revenue Requirement. BPA designed the Slice Rate to collect the same initial amount each year from the Slice Customers, based on the average annual planned cost total for the rate period. BPA then computes the difference between BPA's actual costs in any given year and BPA's planned cost levels in that year. The difference between BPA's actual costs in any given year and BPA's planned cost levels in that year is the basis for the Slice True-Up Adjustment Charge, which the Slice Customers pay or receive a credit for. Because the structure of the Slice Rate and True-Up Adjustment

Charge might operate to deprive Slice Customers of their proportionate share of the benefits (and repayment obligations) under the Settlement in the CY 2004 – 2006 period, BPA determined that a separate agreement would be needed to provide the benefits of the settlement deferrals to Slice Customers. This would be done without changing the Slice Agreement, Slice Rate or the Slice Rate Methodology. The Slice Settlement Agreement is designed to provide the benefits and the obligations of the Settlement to Slice Customers in a similar manner (including timing and proportionate amounts) as BPA's other customers face under their power product purchases. In fact, because BPA's Slice Customers have also purchased a Block product, a portion of their total benefits from the settlement will be afforded them through the SN CRAC mechanisms adopted by BPA and applicable to the Block product.

2. Provisions of Slice Settlement Agreement.

The Slice Settlement Agreement contains the following provisions. These provisions have been summarized and parties should refer to the Agreements themselves for the governing language.

1. Effective Date and Term; Termination. Upon the execution and delivery of the Slice Settlement Agreements by BPA and the Slice Customer, the Slice Settlement Agreements take effect as of the Effective Date (as that term is defined in the Stipulation). The Slice Settlement Agreements will continue in effect until the earlier of September 30, 2011, or the date upon which the last payment required pursuant to the Agreement has been made. The Parties' rights and obligations under the Slice Settlement Agreement will only become effective in the event that the Administrator implements the "Adjustments to FY2004 SN CRAC Percentage Increase" as described in section 6 of the Stipulation ("Settlement Rates"). If the Settlement Rates are not implemented by the Administrator, the Slice Settlement Agreement terminates automatically. In such event, neither BPA nor Slice Customers will be obligated to make the payments described or otherwise perform any other obligation under the Slice Settlement Agreement.

2. Definitions. The Slice Settlement Agreements contain references to terms in the Slice contract and the Stipulation, but one definition is particularly significant. The parties have agreed to a term "Factor," which will calculate the percentage that Slice sales represent of BPA's total firm load obligations (excluding surplus firm sales) for the FY 2007-2011 period. The purpose of the Factor is to ensure that the Slice Settlement Agreement repayment obligation of the Slice Customers during the CY 2007 to 2011 period is either increased or decreased due to changes in BPA's firm load obligations in a similar manner as the repayment obligation of non-Slice Customers. The Factor accomplishes this by distributing the deferral repayment obligations to Slice Customers in proportion to the percentage that Slice sales represent of total BPA firm sales, ensuring that the deferral repayment obligation of Slice Customers is affected by BPA load increases and decreases in a similar manner as non-Slice customers. In the context of this Settlement, application of the Factor to determine the Slice Customers' obligations to pay a share of the deferred IOU Settlement benefits in the FY 2007-2011 period is appropriate and equitable, in order that the Slice Customers may benefit in a comparable fashion with all other non-Slice Customers in the deferral of IOU Settlement benefits to the FY 2007-2011 period. That is, during the FY 2007-2011 period, all customers, including Slice Customers, will pay their share of the deferred IOU Settlement benefits in an amount that is proportionate to the total BPA net firm load that will be allocated these benefits.

3. Background and Scope of Slice Settlement Agreement. Under the Slice Settlement Agreements the parties agree to a set of credits and repayments under two possible accounting treatments, and the attendant billing adjustments, in order to provide a similar treatment for Slice Customers as to the timing and proportion of settlement benefits and obligations as faced by the non-Slice customers. The two possible accounting treatments are (1) the Annual Deferral Amounts are afforded FASB 71 Treatment (deferral qualifies for accounting treatment provided under the provisions of Financial Accounting Standard No. 71, Accounting for the Effects of Certain Types of Regulation), or (2) they are not afforded FASB 71 Treatment. Given the fact that the Slice Settlement Agreements, the Stipulation, and the other Settlement Agreements will be executed prior to BPA being able to obtain review of the contracts' terms from its external auditor, the parties have identified and accommodated both potential accounting treatments for implementing and billing the settlement benefits and obligations. This has been done in a manner that does not in any way alter or change the Slice Agreements, Slice Rate, or Slice Rate Methodology, but that independently provides for payments and credits in recognition of the independent consideration furnished by the customers' forbearance from seeking judicial review of the Stipulation (and the Settlement Documents), covenant not to sue over the Slice Settlement Agreement, and the performance by BPA and the customer of the mutual promises set out in the Slice Settlement Agreement. The following subsections, as paraphrased, describe the treatments.

(a) The Parties understand that under the Slice Agreement, the Slice Rate Methodology and the Slice Rate, the deferral amounts are included in the monthly Slice Rate, and if the Annual Deferral Amounts are accorded FASB 71 Treatment, then (1) such Annual Deferral Amounts would not be included in Actual Slice Revenue Requirement for Contract Years 2004 through 2006 with the consequence that Slice Customers would not pay for their shares of the Annual Deferral Amounts associated with the Slice Product in those years once the True-Up Adjustment Charge has been billed; and (2) such Annual Deferral Amounts would be included in the Slice Revenue Requirement and Actual Slice Revenue Requirement for Contract Years 2007 through 2011, with the consequence that Slice Customers would pay for their shares of the Annual Deferral Amounts associated with the Slice Product in such Contract Years.

(b) The Parties further understand that under the Slice Agreement, the Slice Rate Methodology and the Slice Rate, if the Annual Deferral Amounts are not accorded FASB 71 Treatment, then (1) such Annual Deferral Amounts would be included in Actual Slice Revenue Requirement for Contract Years 2004 through 2006, with the consequence that Slice Customers would pay for their shares of the Annual Deferral Amounts associated with the Slice Product in those years; and (2) such Annual Deferral Amounts would not be included in Slice Revenue Requirement and Actual Slice Revenue Requirement for Contract Years 2007 through 2011, with the consequence that Slice Customers (having already paid their shares of the Annual Deferral Amounts in Contract Years 2003 through 2006) would not pay their shares of the Annual Deferral Amounts associated with the Slice Product in those years.

(c) The consequences of the treatment described in Section 3(a) are that the Slice Customers do not receive the benefits of the Annual Deferral Amounts on a monthly basis, but rather after the Contract Year is over. The consequences of the treatment described in Section 3(b) is that the Slice Customers make payments to BPA years before BPA makes payments to the IOUs, which is a different treatment than the rates for non-Slice Customers. Given these consequences, the Slice Customers that are litigants would not agree to the Stipulation and the Waiver and Covenant Not To Sue and as a result there would be no settlement. The Parties intend for the Slice Settlement Agreement to secure for the Slice Customers the general benefits and obligations comparable to those that will be received by non-Slice Customers under rate schedules applicable to them, as a result of the Stipulation and related Settlement Documents. With regard to the Slice Product, the Parties intend that such general benefits and obligations be secured by the Slice Settlement Agreement in a manner consistent with the Slice Agreement, Slice Rate Methodology and Slice Rate, while at the same time recognizing that separate, independent consideration supports the promises made in the Slice Settlement Agreement. Furthermore, the Parties agree that the Slice Settlement Agreement, operating independently in conjunction with the Slice Agreement, the Slice Rate Methodology, and the Slice Rate, will neither double charge nor double credit the Slice Customers for any amount related to the Monetary Benefit or related interest, and, in the event that one Party claims that a double charge or double credit is occurring, the Parties will negotiate in good faith to resolve the matter prior to resorting to other dispute resolution mechanisms. The Slice Settlement Agreement contains terms and conditions, including those requiring Slice Customers and BPA to make payments to each other at specified times, that implement provisions of the Stipulation and related Settlement Documents, reflect a compromise of disputed claims and defenses, and fulfill the mutual desire of BPA and such customers to end litigation and avoid the costs, risks and uncertainties posed by the litigation to BPA and all of its customers.

4. Further Understandings. The Parties recognize that the purpose of Section 4 of the Slice Settlement Agreement is to document the application of the current Slice Rate, and does not constitute a change to the Slice Agreement, Slice Rate Methodology, or the Slice Rate. The Parties understand the Slice Customers are paying their Selected Slice Percentages of specified annual amounts of Monetary Benefits during the CY2002 through CY2006 period. The Parties further understand that the calculation of the True-up Adjustment Charge following each Contract Year during the CY2002 through CY2006 period will recognize the total annual amount of Monetary Benefit payments to the IOUs, of which Slice Customers are paying their Selected Slice Percentages. The True-up Adjustment Charge calculation following each Contract Year for the CY2002 through CY2006 period will reflect the difference between the actual expenses associated with the Monetary Benefit payments to the IOUs and $147,776,600.

5. Application of the Slice Settlement Agreement. The Slice Settlement Agreement does not address the Slice Customer's Block power purchase which is afforded Benefit s under the SN CRAC applicable to the block product. The Slice Settlement Agreement applies only to Slice Customers' purchases of the Slice Product under the Slice Agreement, and does not change or apply to Slice Customers' payments for purchase of the Block Product under the Slice Agreement.

6. Deferral Amounts Accorded FASB 71 Treatment. Section 6 of the Slice Settlement Agreements addresses the treatment for deferred amounts from the IOUs' Amended Settlement Agreements applicable to the Slice Product purchases in the event that the amounts of deferral receive FASB 71 treatment. Acknowledging that the Slice Agreement, Slice Rate and the Slice Rate Methodology are not being modified, the FASB 71 treatment would result in the Annual Deferral Amounts not becoming expenses in the current rate period. The Annual Deferral Amounts would instead become expenses in the FY 2007 to 2011 period consistent with the payment obligation BPA has to the IOUs under the Amended Settlement Agreements. To ensure that the Slice Customers receive their settlement benefits at a similar time as the non-Slice Customers, the Slice Settlement Agreement provides a billing adjustment (credit) in the customer's favor and shown on its monthly Slice Expedited Bill. If Section 6 of the Slice Settlement Agreement is applied then Section 7, its alternative, is not. If Annual Deferral Amounts are accorded FASB 71 Treatment, then BPA will provide prompt written notice of this treatment to Slice Customers.

For Contract Years 2007 through 2011, Slice Customers' monthly Expedited Bills will include a Slice Settlement Agreement credit by BPA for the difference between what the Slice Customers pay in their Slice Rate for the deferred IOU Settlement benefits and what they should be paying when the Factor is applied to the deferred IOU Settlement benefits.

7. Deferral Amounts Not Accorded FASB 71 Treatment. Section 7 addresses the circumstance in which, after execution of the settlement package, BPA does not receive FASB 71 treatment for the IOU payments deferred under the settlement. Without FASB 71 treatment, the Annual Deferral Amounts would remain as current expenses in the FY 2004-2006 period. BPA will bill the Slice purchasers monthly for these amounts under their Slice Agreements. Under the Slice Settlement Agreement, BPA is separately agreeing to pay to the Slice Customer an amount equal to the Slice Customer's share of the Annual Deferral Amounts by providing an adjustment on its monthly bill in order that the benefit of the settlement can be obtained by the Slice Customer. In return, Slice Customers are agreeing to pay to BPA in the FY 2007 to 2011 period amounts equal to the deferral repayments made by BPA to the IOUs, adjusted by the Factor discussed previously. The Slice Customer's promise to pay is a separate obligation from its Slice Agreement payments, since the Annual Deferral Amounts were expenses in the FY 2004 to 2006 period under the Slice Agreement. Absent its promise under the Slice Settlement Agreement, the Slice Customer would have already paid those expenses under the Slice Agreement. If Annual Deferral Amounts are not accorded FASB 71 Treatment, BPA will provide prompt written notice of this treatment to Slice Customers. In the event that Section 7 applies, Section 6 does not apply.

8. Deferrals Terminated Prior To September 30, 2006. BPA will provide prompt written notice to the Slice Customers stating the month of termination of the deferral of IOU monetary benefits under the Settlement Amendments (Termination Month), if such occurs. If the Annual Deferral Amounts are terminated prior to September 30, 2006, the Slice Settlement Agreement describes the payment obligations of BPA and the Slice Customers. If the Annual Deferral Amounts have been accorded FASB 71 Treatment, then the payment obligations are determined pursuant to Section 8(a) of the Agreement. If the Annual Deferral Amounts have not been accorded FASB 71 Treatment, then the payment obligations will be calculated pursuant to Section 8(b) of the Agreement. In either case, the payment obligation of the Slice Customers will be similar to the payment obligation of the non-Slice Customers, all as specified in the Slice Settlement Agreement.

9. Interest Payment. The parties identified the possibility that Slice Customers could be charged twice for annual within year interest applicable to the Annual Deferral Amounts, once in the Actual Slice revenue requirement and once in the payments to BPA under the Slice Settlement Agreement. This provision addresses a payment made by BPA to the Slice Customer to avoid double charging for interest on the Annual Deferral Amounts.

10. Payment of Separate Line Items. The separate line items included in any Expedited Bill pursuant to sections 6, 7, 8 and 9 of the Slice Settlement Agreement will be deemed to be part of such Expedited Bills. The payment and dispute resolution provisions of the Slice Agreement will be used to address disputes over the separate line items included in any expedited bill under the above-noted sections. Such separate line items (a) are independent of the Slice Agreement, Slice Rate and Slice Rate Methodology, and (b) are not part of or subject to any right of the Slice Customers to conduct an audit under section 4 of the Slice Agreement.

Finally, the Agreement contains a number of miscellaneous provisions, including: that the payment and dispute resolution provisions of the Slice Agreement will be utilized to determine disputes over the separate line items included in any Expedited Bill pursuant to the Agreement; nothing in the Agreement has any precedential effect other than for purposes of the Agreement; the Agreement does not change the Slice Rate, the Slice Rate Methodology, or the Slice Agreement; the parties will not challenge the Agreement, the Stipulation and the Settlement Documents; provisions providing for notice and cure in case of a payment breach, an option for liquidated damages (the total of amount of net payments that would have been made to the non-defaulting Party under the Slice Settlement Agreement had such failure to perform not occurred) in case of a failure to cure; covenants requiring the parties not to take actions or assert positions that would change the amount or timing of payments required under the Agreement; severability provisions; and various standard provisions regarding amendments, information exchange and confidentiality, entirety of agreement, exhibits, no third party beneficiaries, waivers, and notice.

II. BPA FINDINGS ON IOU MONETARY BENEFITS AND SLICE SETTLEMENT AGREEMENT

When BPA develops contracts and rates, BPA must comply with all statutory and regulatory requirements. The monetary payments to the IOUs, and the calculations of such monetary payments, in sections 4(c) and 5 of the Amended Settlement Agreements, constitute neither a rate nor a sale of power as those terms are used in the Pacific Northwest Electric Power and Conservation Act. Also, the offering and execution of the Slice Settlement Agreement does not constitute a change or modification to the Slice Rate, the Slice Rate Methodology or the Slice Agreement.

III. FINAL ACTION

This Record of Decision, including the offer of the Stipulation and Agreement for Settlement and attendant contracts, contract amendments, and other documents, constitutes BPA's final action as of the date of this ROD. For purposes of judicial review under the Northwest Power Act, all challenges to this final action must be filed within 90 days of the date of this ROD in the United States Court of Appeals for the Ninth Circuit or be barred. 16 U.S.C. § 839f(e)(5). BPA has the authority to enter into contractual agreements and to modify such agreements, including independent settlement authority for resolving disputes regarding BPA's contractual agreements with other parties in both administrative and judicial forums.

CONCLUSION

In summary, the settlement of litigation challenging the IOUs' REP Settlement Agreements, the RPSAs, the public agencies' Slice contracts, and BPA's Supplemental Power Subscription Strategy, as reflected in the Stipulation, amendments to the IOU's REP Settlement Agreements, and Slice Settlement Agreements, among other documents, would, in effect, provide for the continuation of the Reduction of Risk Discount through September 30, 2006. In addition to the $200 million reduction and the existing $55 million IOU deferral of benefits into the FY 2007-11 period, additional deferrals of $75 million per year for the remaining three years of the rate period ($225 million) would lead to a total reduction in BPA's revenue requirement in the current rate period of approximately $480 million. Such a reduction would result in a significant reduction in rates in the current rate period, which would be of enormous benefit to the Pacific Northwest region during troubled economic times.

The elimination of pending litigation challenging the IOUs' REP Settlement Agreements and the Slice Agreements also will remove a substantial uncertainty from operation under those agreements for the remaining 8 years of their terms for both BPA and its customers.

In addition, the elimination of possible power deliveries and the provision of only monetary benefits to the IOUs in the FY 2007-2011 period will reduce the need for BPA to acquire additional power supplies from the wholesale power market. This will reduce BPA's reliance on the unpredictable and volatile wholesale power market, which should enhance the stability of BPA's rates.

I have reviewed and evaluated the record compiled by BPA on the proposed litigation settlement, including the Stipulation, the IOUs' Amended Settlement Agreements, the Slice Settlement Agreements and other documents. Based upon the record, the reasoning contained therein, and all requirements of law, I hereby adopt the proposed Stipulation and Agreement for Settlement and the attendant contracts, amendments and other related documents. The evaluations and decisions used in the development of the Stipulation for Settlement and attendant documents are adequately covered by BPA's 1998 Power Subscription Strategy ROD, BPA's 1998 Power Subscription Strategy NEPA ROD, BPA's Business Plan EIS, and BPA's Business Plan ROD.

Issued at Portland, Oregon, this 21st day of October, 2003.

/s/
Stephen J. Wright
Administrator and Chief Executive Officer