applications to OPIC. Applications will be reviewed by OPIC and DOE and applicants that meet OPIC Requirements and the Program's Selection Criteria, will be considered for the program. Specific information on OPIC Requirements and Program's Selection Criteria is available on the OPIC website *(http://www.opic.gov).*

Dated: November 9, 2000.

Theresa Fariello,

Deputy Assistant Secretary, Office of International Energy Policy, Office of International Affairs.

[FR Doc. 00–30639 Filed 11–30–00; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Secretary of Energy Advisory Board; Meeting

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an open meeting of the Secretary of Energy Advisory Board's Laboratory Operations Board (LOB). The Federal Advisory Committee Act (Public Law 92–463, 86 Stat. 770), requires that agencies publish these notices in the **Federal Register** to allow for public participation.

NAME: Secretary of Energy Advisory Board—Laboratory Operations Board.

DATES: Thursday, December 7, 2000, 8:30 a.m.–3:15 p.m., Eastern Standard Time.

ADDRESSES: Hilton Washington Embassy Row Hotel, 2015 Massachusetts Ave., NW., Washington, DC 20036

FOR FURTHER INFORMATION CONTACT: Mary Louise Wagner, Executive Director, or Laurie Keaton, LOB Staff Director, Office of Secretary of Energy Advisory Board (AB–1), US Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586–7162 or (202) 586–6279 (fax).

SUPPLEMENTARY INFORMATION: The purpose of the Laboratory Operations Board is to provide independent external advice to the Secretary of Energy Advisory Board regarding the strategic direction of the Department's laboratories, the coordination of budget and policy issues affecting laboratory operations, and the reduction of unnecessary and counterproductive management burdens on the laboratories. The Laboratory Operations Board's goal is to facilitate the productive and cost-effective utilization of the Department's laboratory system and the application of best business practices.

Tentative Agenda

Thursday, December 7, 2000

8:30 a.m.–9 a.m.—Co-Chairs Opening Remarks
9 a.m.–9:45 a.m.—Budget and Appropriations Update
9:45 a.m.–10 a.m.—Break
10 a.m.–11 a.m.—Presentation on Hamre Commission: Study of the Science and Security Functions of the Department
11 a.m.–12 p.m.—Presentation on Transition Planning at DOE
12 p.m.–1 p.m.—Lunch
1 p.m.–3 p.m.—LOB Work Plan—Status Reports
—Implementation of Performance Based Management at DOE
—LOB Retrospective
—Laboratory Profile Report Update
3 p.m.–3:15 p.m.—Public Comment Period
3:15 p.m.—Adjourn

This tentative agenda is subject to change.

Public Participation: In keeping with procedures, members of the public are welcome to monitor the business of the Laboratory Operations Board and to submit written comments or comment during the scheduled public comment period. The meeting will be conducted in a fashion that will, in the Co-Chairs' judgment, facilitate the orderly conduct of business. During its open meeting, the Laboratory Operations Board welcomes public comment. Members of the public will be heard in the order in which they sign up at the beginning of the meeting. The Board will make every effort to hear the views of all interested parties. You may submit written comments to Mary Louise Wagner, Executive Director, Secretary of Energy Advisory Board, AB–1, US Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585. This notice is being published less than 15 days before the date of the meeting due to the late resolution of programmatic issues.

Minutes: A copy of the minutes and a transcript of the meeting will be made available for public review and copying approximately 30 days following the meeting at the Freedom of Information Public Reading Room, 1E–190 Forrestal Building, 1000 Independence Avenue, SW., Washington, DC, between 9 a.m. and 4 p.m., Monday through Friday except Federal holidays. Further information on the Laboratory Operations Board is available at the Secretary of Energy Advisory Board's web site, located at *http://www.hr.doe.gov/seab.*

Issued at Washington, DC, on November 28, 2000.

Rachel M. Samuel,

Deputy Advisory Committee Management Officer.

[FR Doc. 00–30681 Filed 11–30–00; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Bonneville Power Administration

Bonneville Power Administration's Proposed Amendments to 2002 Wholesale Power Rate Adjustment Proposal

AGENCY: Bonneville Power Administration, DOE.

ACTION: Notice of proposed amendments to 2002 wholesale power rate adjustment proposal: public hearing, and opportunity for public review and comment proposal BPA File No: WP–02.

SUMMARY: The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) provides that Bonneville Power Administration (BPA) must establish and periodically review its rates so that they are adequate to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, and to recover the Federal investment in the Federal Columbia River Power System (FCRPS) and other costs incurred by BPA. By this notice, BPA announces a proposed amendment to the 2002 rate proposal (BPA Docket WP–02), consideration of which has been stayed by Federal Energy Regulatory Commission (FERC) in Docket No. EF00–2012–000. The 2002 rates replace the current 1996 rates, which expire on October 1, 2001, at the same time that most of BPA's current power supply contracts terminate.

DATES: Proposed hearing dates are supplied in the Supplementary Information Section I.C. below. Close of public comments is February 14, 2001.

ADDRESSES: Written comments should be submitted to: Mr. Michael Hansen, Public Involvement and Information Specialist, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212. Documents will be available for public viewing after December 12, 2000, at BPA's Public Information Center, BPA Headquarters Building, 1st Floor; 905 NE. 11th, Portland, Oregon, and will be provided to parties at the prehearing conference to be held on December 12, 2000, from 9 a.m. to 12 p.m., Room 223, 911 NE.

11th, Portland, Oregon. The documents will also be available on BPA's web site at www.bpa.gov/power/ratecase. Mr. Barney Keep, Acting Power Manager, Power Products, Pricing and Rates, is the official responsible for the development of BPA's rates.

FOR FURTHER INFORMATION CONTACT: Interested persons may call (503) 230–4328 or call toll-free 1–800–622–4519.

SUPPLEMENTARY INFORMATION:

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Part I—Introduction and Procedural Background

A. Relevant Statutory Provisions Governing This Rate Proceeding

Section 7 of the Northwest Power Act, 16 U.S.C. 839e, contains a number of general directives that the BPA Administrator must consider in establishing rates for the sale of electric energy and capacity. In particular, section 7(a)(1), 16 U.S.C. 839e(a)(1), provides in part that:

> [s]uch rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law.

Rates established by BPA are effective on an interim or final basis when approved by FERC. 16 U.S.C. 839e(a)(2). Similar rate directives may also be found in the Bonneville Project Act, 16 U.S.C. 832 *et seq.*, the Federal Columbia River Transmission System Act, 16 U.S.C. 838 *et seq.*, and the Flood Control Act of 1944, 16 U.S.C. 825 *et seq.*

Section 7(i) of the Northwest Power Act, 16 U.S.C. 839e(i), requires that BPA's rates be set according to procedures which include:

- Issuance of a **Federal Register** notice announcing the proposed rates;
- One or more hearings;
- The opportunity to submit written views, supporting information, questions, or arguments; and
- A decision by the Administrator based on the record developed during the hearing process.

This notice is intended to advise parties that BPA will be conducting additional hearings in WP–02 for the purpose of amending the proposal currently before FERC. This proceeding will be governed by BPA's ''Procedures Governing Bonneville Power Administration Rate Hearings,'' 51 FR 7611 (March 5, 1986). Special rules governing the proceeding may also be adopted at the prehearing conference.

B. Background

On August 13, 1999, BPA filed a notice in the **Federal Register**, 64 FR 44318 (1999), proposing new wholesale power rates to be effective on October 1, 2001. BPA's initial rate proposal, along with written testimony and studies, was filed on August 26, 1999. Parties to the proceeding filed their direct testimony on November 2, 1999. On December 17, 1999, litigants filed rebuttal to the Parties' direct cases. The Parties also filed prehearing briefs on December 17, 1999. Cross-examination began on January 24, 2000. Parties submitted initial briefs on February 28, 2000. Oral argument before the BPA Administrator was held on March 2, 2000.

A Draft Record of Decision (ROD) was published on April 10, 2000. Parties filed briefs on exceptions on April 24, 2000. BPA published its Final ROD on May 15, 2000. BPA then filed its proposed rates with the FERC on July 6, 2000. BPA requested approval of the rates and General Rate Schedule Provisions (GRSPs) effective October 1, 2001, through September 30, 2006.[1] BPA requested interim approval of its proposed rates by September 15, 2000, and final approval by January 19, 2001. On July 17, 2000, FERC issued notice of BPA's rate filings. See U.S. Department of Energy, Bonneville Power Admin., 65 FR 44041. In the notice FERC established Docket No. EF00–2012–000 to review BPA's proposed rates. On August 7, 2000, BPA requested a 30-day stay of proceedings at FERC. On September 4, 2000, BPA filed an additional motion with FERC requesting a stay of the proceedings through April 30, 2001.

[1] BPA also requested approval of the methodology used to calculate the rate for the Slice product sold under the Priority Firm (PF) rate schedule for a period from October 1, 2001, to September 30, 2011.

C. Proposed Schedule Concerning This Rate Proceeding

BPA will release its proposed 2002 amendments on December 12, 2000, and expects to publish a final Record of Decision by June 2001. The following proposed schedule is provided for informational purposes. A final schedule will be established by the Hearing Officer at the prehearing conference on December 12, 2000.

December 18: Clarification.
January 3: Motions to Strike.
January 5: Data Request Deadline.
January 10: Answers to Motions to Strike.
January 12: Data Response Deadline.
February 1: Parties File Direct Case.
February 8: Clarification.
February 16: Motions to Strike.
February 14: Close of Participant Comments.
February 20: Data Request Deadline.
February 23: Answers to Motions to Strike.
February 27: Data Response Deadline.
March 6: Litigants File Rebuttal.
March 14: Clarification.
March 19: Motions to Strike.
March 19: Data Request Deadline.
March 26: Answers to Strike.
March 26: Data Response Deadline.
April 4–6: Cross-Examination.
April 16: Initial Briefs Filed.
April 26: Oral Argument.
May 25: Draft ROD issued.
June 5: Briefs on Exception.
June 20: Final ROD—Final Studies.

Part II—Purpose and Scope of Hearing

BPA's proposed amendments are necessary because market prices are expected to be much higher and more volatile than assumed in the 2002 rate proposal. BPA's cost-based rates are now further below market price expectations for the FY 2002–2006 rate period. As a result of high market prices, BPA now expects much greater demand for service from customers, demand that BPA is required to serve and that exceeds the generating capability of the FCRPS. To meet this increased load obligation, BPA will need to make substantially greater power purchases in the market at substantially higher and more uncertain prices than anticipated in revenue requirements for the 2002 rate proposal. An adjustment to BPA's 2002 proposal is, therefore, necessary to ensure rates and revenue will be sufficient to recover the costs with a high degree of certainty.

BPA's proposal deals with this cost recovery problem by amending certain risk mitigation tools contained in the 2002 General Rate Schedule Provisions (GRSPs), which apply to the base rates. BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. This hearing provides Parties and Participants an opportunity to respond to BPA's proposal.

A. Procedural Background

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

BPA concluded that, in light of the unprecedented price spikes during the summer months, BPA's cost-based rates for 2002–2006 would be far more attractive to prospective customers than market alternatives. As a result, preference customers could be expected to purchase significantly more power than originally anticipated. Due to higher market prices, there was both an increase in demand and higher augmentation purchases than previously expected. 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). BPA now expects loads will exceed the original rate case forecast by an additional 1,522 aMW. Moreover, the difficulty of forecasting the expense of serving the increased load obligations is magnified by the fact that prices are escalating in an extraordinarily volatile market.

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

The increased load obligations that BPA will be meeting through market purchases in a currently escalating and volatile market environment have decreased TPP to just such an unacceptable level. BPA is implementing the Fish and Wildlife Principles (Principles) in this rate proposal. Among other provisions, the Principles call for a TPP goal of 88 percent, and an acceptable range of 80 to 88 percent for the 5-year, 2002–2006 rate period. The rates and risk mitigation tools were initially developed to achieve the TPP goal of 88 percent in full. After the rates were filed at FERC, increases and uncertainty surrounding augmentation purchase costs drove the TPP estimate to well below 70 percent.

To remedy the cost recovery problems so that TPP fell within the acceptable range, BPA began in early August to explore its options. On August 1, 2000, BPA suspended the signing of any new power contracts with customers and initiated a separate public process to examine the problem and explore potential solutions. On August 3, 2000, BPA wrote a letter to rate case parties and other interested entities in the region, outlining two possible options for dealing with the problem. The first option entailed modifying a five-year rate lock provision in BPA's power contracts, to give BPA the ability to reset rates if necessary after September 30, 2003. The second option involved modifying the 2002 rate filing to address the problem. The letter requested written comment regarding the proposed options or any other ideas the parties had for addressing the problem.[2] In addition, BPA set August 9, 2000, for a technical discussion of the issues facing BPA and August 21, 2000, for a public meeting to discuss the range of options.

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

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

1. How should the CRAC be redesigned to provide BPA with the necessary financial protection?

2. How should the Slice product be modified to insure that Slice customers pay an equitable share of BPA's augmentation costs?

3. What changes, if any, are necessary to the proposed settlement of the IOUs Residential Exchange benefits, as a consequence of the revision to the CRAC?

4. How would the proposed changes to the CRAC impact customers who had already signed contracts?

BPA notified FERC on September 4, 2000, of its decision to pursue modifications to the CRAC and requested that the stay be extended through April 30, 2001, so that settlement discussions could be continued and a limited 7(i) proceeding could be conducted. During the month of September, BPA and rate case parties engaged in a series of meetings to discuss ways of resolving the four major issues described above. Despite this effort, the parties were unable to reach a consensus.

On October 6, 2000, BPA notified rate case parties that it intended to initiate a limited 7(i) proceeding to revise the CRAC; make adjustments to the Slice methodology; adjust the Residential Exchange Settlement; and address the Subscription contracts signed earlier this summer in order to deal with the issues facing BPA. The Administrator

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

set the close of business on October 16, 2000, as the start of *ex parte.*[3]

B. Scope of Proceeding

This additional hearing will address the problems created by increased purchase power costs created due to increased loads resulting from higher prices in a volatile market environment. In this second phase of the 2002 rate case, the Administrator will not open issues previously determined to be outside the scope of the first phase of the rate case, as described in the original 1999 **Federal Register** notice[4] and in the phase one WP–02 ROD. BPA's proposal to amend the risk mitigation tools, rather than revise the base rates, does not require that BPA reexamine in this proceeding every issue that was debated and decided in the earlier phase of this proceeding. Many of those issues are not germane to the cost recovery problem that this amended proceeding has been initiated to address.

Therefore, the scope of this second phase of the proceeding is limited only by those guidelines the Administrator established during the first phase of this proceeding, a summary which is described below, and the parameters of the specific problem that is being addressed in this phase of the proceeding.

C. Previous Limitations on Scope

On August 13, 1999, pursuant to Rule 1010.3(f) of BPA's Procedures, the Hearings Officer was directed to exclude from the record any evidence or arguments related to five specific areas.

The first area of exclusion concerns the Cost Review recommendations and BPA's planned implementation of those recommendations which received extensive public review. This rate proceeding will not revisit the methodology used to develop the Cost Review recommendations, the policy merits or wisdom of the specific recommendations, or BPA's implementation plans.

The second area of exclusion concerns decisions made in the Subscription Strategy. The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit decisions that were made in BPA's Subscription Strategy, including both the ROD and Supplemental ROD for the Strategy.

The third area of exclusion concerns decisions made in the context of the Fish and Wildlife Funding Principles. The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit the policy merits or wisdom of the strategy to ''keep the options open'' or of the Fish and Wildlife Funding Principles.

The fourth area of exclusion concerns transmission issues not part of the rate case or included in the settlement agreement reached in BPA's transmission rate case.

The fifth area of exclusion concerns adjustments to the PF–96 Rate.[5]

For this second phase of the proceeding, the Administrator again directs the Hearings Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek in any way to address the five areas noted above. Also, the Targeted Adjustment Charge, for Uncommitted Loads has been approved on a final basis by FERC in Docket No. EF00–2013–000. Therefore, the Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to make which seek to change the outcome of that proceeding or which would have such an effect.

Part III—BPA's Proposed Solution to Cost Recovery Problem

To address cost recovery issues caused by the additional load and escalating market, BPA is proposing changes to the CRAC and some corresponding modifications to the Slice methodology. This solution provides sufficient assurance of cost recovery while achieving other goals, as outlined below.

A. The Subscription Strategy

The WP–02 rate proposal was designed to implement the decisions made in BPA's Subscription Strategy. The Subscription Strategy was the result of a lengthy public process that began with the Comprehensive Regional Review. The Subscription Strategy was fundamentally a blueprint for how BPA should go about filling the void that would be left after the vast majority of its contracts expire in 2001. The Strategy provided a structure around which BPA could offer new contracts and meet its statutory obligations while responding to the myriad of changes that had occurred since enactment of the Northwest Power Act.

Some of these changes were due to deregulation of the wholesale power market that began in the 1990s. These changes forced BPA to become more competitive and to unbundle its power products consistent with the open access to transmission and the more competitive climate in the wholesale power markets. The Subscription Strategy also mapped out a general plan for how the benefits of the FCRPS would be distributed in this new climate, consistent with the requirements and obligations created by the Northwest Power Act. In part, this meant attempting to strike a delicate balance between a wide range of competing interests, including customer groups, governmental entities, tribal representatives, and public interest groups.

In sum, the Subscription Strategy reflected the varied and complex interests in the Pacific Northwest and laid the groundwork for an equitable distribution of the benefits of the FCRPS consistent with legal requirements. The four principal goals of the Subscription Strategy are:

- Promote the spread of 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.
- Fulfill BPA's fish and wildlife obligations while assuring a high level of Treasury payment.
- Provide market incentives for the valuation of conservation and renewable resources.

Of course, the primary purpose of this proceeding is to determine how to deal effectively with the cost recovery risk associated with higher and more uncertain purchase power costs. This increased uncertainty is being caused by expected increases in rising prices in a volatile market and resultant increases in load obligations. However, this phase of the proceeding begins, as did the initial phase, with the basic assumption that a solution to the problem should, as much as possible, be designed to preserve the basic principles underlying the Subscription Strategy. That basic framework has been developed over a period of several years, reflects a wide range of public processes, and is predicated on the input of all regional interests and stakeholders. It continues to provide reasonable direction and structure for the rights and corresponding obligations that have

[3] *On the effective date, ex parte* communications regarding the merits of this proposal with any BPA or DOE employee are prohibited.

[4] The details of the elements that were excluded from the earlier proceeding are described in detail at 64 FR 44318–44323 (Aug. 13, 1999).

[5] FERC granted final approval of TACUL on October 26, 2000, in docket EF00–2013–000. 93 FERC ¶ 62,062 (2000).

been embodied in contracts for service beginning October 1, 2001.

B. Status of Subscription Contracts

All of BPA's regional customers have signed either a Subscription contract or a settlement agreement prior to the October 31, 2000, contract-signing deadline.[6] The Subscription contracts translated the Subscription Strategy into product offerings and formalized the proposed distribution of power and benefits developed through the Subscription Strategy. The proposed WP–02 rates establish the price for those contracts. The contracts were offered to customers and all of BPA's regional customers have already signed, indicating their commitment to subscribing for power during the next rate period. BPA's proposal to amend the WP–02 rate filing through adjustments to the CRAC will preserve the proposed WP–02 rates, except for the few specific changes noted below.

C. Proposed Modifications to Cost Recovery Adjustment Clause (CRAC)

The proposed three-stage CRAC, described in detail below, addresses the cost recovery uncertainty caused by the unanticipated developments in the market. In the Subscription Strategy, BPA stated that a CRAC was an integral part of BPA's risk mitigation package in the development of its power rates. Subscription Strategy, at 14. The CRAC proposed, and eventually adopted in the ROD, was an adjustment to posted rates for all net firm power load requirements customers. *Id.* BPA's final proposal contained a CRAC that, when combined with Planned Net Revenues for Risk (PNRR) and other risk mitigation tools, produced a TPP that met BPA's stated objectives.

The CRAC was designed to trigger when BPA's accumulated net revenues were reduced to below certain threshold levels. If the accumulated net revenues fell below these established thresholds, a financial adjustment would be made to the base rates. The amount of the annual adjustment was capped at preestablished levels. The values used for the initial proposal had the accumulated net revenue equivalents of reserve thresholds of $300 million in FY 2001–2002 and $500 million in FY 2003–2005. The proposal also provided that if BPA's accumulated net revenues are reduced to below the threshold levels, the annual cap for the rate adjustment for FY 2001 was $125 million, FY 2002 was $135 million, FY 2003–2004 was $150 million, and FY 2005 was $87.5 million.

In the first phase of the proceeding, BPA forecasted a need to augment its system with market purchases to meet its obligations. However, the existing rate proposal contemplated a lesser amount of augmentation purchases in a far less volatile market. Because the difference between BPA's rates and the market prices has increased dramatically, BPA's customers are not diversifying their sources of power as anticipated. Therefore customers have placed a greater portion of their load on BPA and BPA expects that the price BPA will pay for the power needed to serve that additional load will be higher than originally forecast.

To be specific, in the rates now before FERC BPA assumed it would need to augment the system by 1,732 aMW at a price of $28.10/megawatthour (MWh) for the power, while current estimates have BPA augmenting the system by 3254 aMW (an additional 1,522 aMW) at a market price in excess of $40.00/MW. As a consequence of these interrelated factors, the assumptions used in the original rate filing no longer adequately account for the anticipated expenses and financial risks in the next rate period. The risks, however, are fundamentally associated with three assumptions: market price, market volatility, and resultant increase in the load forecast. These three factors can be managed effectively and accurately by adjusting the CRAC to achieve a sufficient assurance of cost recovery.

D. CRAC Redesign

In its earlier ROD, BPA proposed a single CRAC that triggered upon accumulated net revenues (ANR) dropping to pre-identified levels. The amendment now being proposed envisions a three-stage CRAC, with each stage designed to deal with a different aspect of the problem. The three stages are referred to as the Load-Based CRAC (LB CRAC), Financial-Based CRAC (FB CRAC), and Safety-Net CRAC (SN CRAC).

The LB CRAC is primarily designed to address the problem of loads exceeding the forecast from the WP–02 Final Studies. The LB CRAC will be based on MW amounts in contracts already signed by customers. As a consequence, the load projection used for the LB CRAC will provide a very accurate indication of how much load BPA will actually be required to serve in the upcoming rate period. Therefore, BPA's risk of unforeseen exposure to the market, in terms of the amount of augmentation purchases required to serve load, is effectively mitigated by the LB CRAC.

Potential exposure to higher market prices and increased volatility as well as other risks, are addressed by the FB CRAC. The uncertainties surrounding the current market make it difficult to project, with a high degree of certainty, the prices that BPA may be required to pay for the power needed to augment the system. The result is that BPA will be purchasing in a volatile market to a much greater extent, increasing the risk of exposure to higher than projected market prices. The proposed FB CRAC makes it possible for BPA to mitigate the risk of forecasting error related to market prices. This is accomplished by allowing BPA to maintain a stable and sufficient level of financial reserves that will enable it to fulfill its load obligations in the face of variability and unpredictability in market prices.

The level of uncertainty presented by the current market volatility may under some circumstances cause BPA to forecast a deferral of its Treasury payment. The SN CRAC provides BPA with a tool to temporarily adjust posted power rates for Subscription sales upward in the event that a Treasury deferral will occur despite implementation of the LB CRAC and the FB CRAC. The SN CRAC would likely not trigger soon enough to avoid an initial deferral, but would help to avoid a second deferral.

1. Load-Based CRAC (LB CRAC)

The LB CRAC is designed to address the problem of recovering the costs associated with additional augmentation caused by unanticipated load placed on BPA, in large part by high market prices. The LB CRAC will be implemented if the actual augmentation for the five-year rate period exceeds the amount of augmentation forecasted in the WP–02 Final Studies (1,732 aMW). Based upon the signed Subscription contracts, BPA will exceed the forecast augmentation amounts contained in the WP–02 Final Studies by 1,522 aMW. BPA is proposing to impose the LB CRAC based on the additional (1,522 aMW) amount of augmentation along with that portion of the augmentation forecasted in the May 2000 WP–02 Final Studies but not purchased as of August 1, 2000.

The total amount collected under the LB CRAC will be calculated in three different ways depending upon whether the MWs of augmentation were forecast in the May 2000 WP–02 Final studies. For the 1,522 aMW of augmentation not forecast in the WP–02 the amount of revenue to be collected is determined by

[6] BPA offered its IOU customers a Settlement Agreement as an alternative to the benefits under the standard Residential Power Sales Agreement (RPSA). Customers who did sign contracts prior to the close of the signing window may still do so but they will be subject to the Targeted Adjustment Clause (TAC).

multiplying this additional amount of augmentation by the difference between the assumed flat purchase price of $34/megawatthour (MWh) and the flat PF rate of $19.26/MWh. For the MWs of augmentation forecasted but not purchased by August 1, 2000, the amount of revenue to be collected is determined by multiplying those MWs by the difference between $34/aMW and $28.1/aMW. There are, however, 46 aMW in the WP–02 Final Studies that had a forecasted augmentation cost of $23/MWh. These MWs will be assessed the difference between $34 and $23. The sum of these revenue amounts will then be multiplied by the percentage of Non-Slice Load to Total Requirements Load, to arrive at the total revenue amount to be collected from those customers subject to the LB CRAC. The total revenue amount under the LB CRAC will be converted into a percentage increase to the base rate for the entire rate period and would apply to the total charge for energy, demand, and load variance.

The LB CRAC applies to power customers under the following firm power rate schedules:

1. PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription];
2. Industrial Firm Power (IP–02), including power sold under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate;
3. Residential Load (RL–02);
4. New Resource Firm Power (NR–02); and
5. Subscription purchases under Firm Power Products and Services (FPS).

The LB CRAC does not apply to:

1. PreSubscription rates;
2. the financial portion of the Residential Exchange settlement; or
3. Slice purchases.

2. Financial-Based CRAC (FB CRAC)

The FB CRAC is designed to address the problem presented by market prices for augmentation being forecasted to be significantly higher and more volatile than what was originally expected. It would also trigger in the event that other events, such as low water conditions or WNP outages, sufficiently deplete financial reserves. The FB CRAC has a similar design to the CRAC in the May 2000 WP–02 Final Studies. It entails a temporary, upward adjustment to posted power rates for Subscription sales if ANR in the generation function are forecasted to fall below preestablished threshold levels. If the ANR at the end of any FY 2002–2006 is forecast to fall below the FB CRAC threshold applicable to that FY, the FB CRAC triggers, and a cost recovery adjustment rate increase will go into effect.

The FB CRAC applies to power customers under these firm power rate schedules:

1. PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription];
2. Industrial Firm Power (IP–02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate;
3. Residential Load (RL–02);
4. New Resource Firm Power (NR–02); and
5. Subscription purchase under Firm Power Products and Services (FPS).

The FB CRAC does not apply to:

1. PreSubscription contracts;
2. the Slice purchases; or
3. the financial portion of the Residential Exchange Settlement.

The FB CRAC would be based on a forecast of end-of-year ANR and would result in a percentage increase in rates to restore ANR to the lower of the threshold level or the maximum amount of the annual cap. Unlike the LB CRAC, the FB CRAC would trigger only in those years when ANR is forecasted to fall below the threshold and any collection under the FB CRAC would occur only in those years when it is triggered. The threshold levels and the annual caps for the CRAC in this proposal would also differ from those proposed in the WP–02 ROD. The ANR threshold levels for the five years of the rate period in 2002 are $98M; in 2003 are $41M; and in 2004, 2005 and 2006 are $7M. The annual cap is $330M.

Under BPA's earlier CRAC proposal, BPA's determination of whether the threshold level was reached was based upon audited actual financial data. This approach was an after-the-fact determination of whether BPA's ANR dropped below the threshold levels. Under the FB CRAC, rather than basing the determination on audited actual financial data, the trigger will be based upon a forecast of ANR. One of the originally stated objectives for the CRAC was to achieve cap and threshold levels that did not make implementation impractical. Basing the determination on a forecast helps to achieve this objective by allowing BPA to collect any money due under the FB CRAC sooner. Relying on audited actual financial data, as envisioned earlier, would require BPA to have a CRAC with a higher threshold and cap levels to maintain the same TPP level. Therefore in order to keep the CRAC threshold and cap levels lower and more manageable, BPA is proposing to base the FB CRAC on a winter forecast of end-of-year ANR.

A potential problem with basing the FB CRAC trigger of ANR on a forecast, rather than audited actual financial data, is the possibility of forecasting error. To remedy this possibility, BPA is proposing that the forecast be trued-up to actual financial data once it is available. Therefore, if BPA over or under collects, an adjustment would be made to correct the problem.

A second difference between the CRAC in the WP–02 ROD and the FB CRAC is the manner in which the CRAC amount is collected. The original CRAC was designed to be assessed and collected monthly over 12 months, based upon the percent of the adjustment. Under this proposal the FB CRAC would be assessed and collected in 4 monthly payments rather than 12. The payments would be assessed beginning in March, and all funds would be collected by June 30 of the year. As mentioned above, the intent in collecting the funds in a short period of time before June 30 is to make the FB CRAC thresholds and cap lower and therefore the total revenues collected under the FB CRAC lower. Payments to BPA after June 30 by many public customers become ''net billing'' assets and must be made to Energy Northwest under the terms of the bond agreements. BPA can achieve lower thresholds and caps and maintain the same TPP level, if the amounts due under the FB CRAC are collected before the end of June.

3. Safety-Net CRAC (SN CRAC)

The third stage, or SN CRAC, is designed to trigger when BPA is forecasting a 50 percent probability of a missed Treasury payment, or there is an actual miss. If, after triggering the LB and FB CRACs, BPA is still projecting a Treasury miss, or has actually missed a Treasury payment, the SN CRAC would allow BPA to propose an upward adjustment to posted power rates for Subscription sales through modification of the same parameters used in the FB CRAC. A public process will be conducted to determine the extent to which the SN CRAC changes could have an amount to be collected, the duration and the timing different from the FB CRAC. At the end of the public process the Administrator will make a final decision on the SN CRAC. The SN CRAC gives BPA a flexible mechanism to deal with a wide scope of potential financial problems, even those unrelated to market effects.

E. Other Issues

1. Slice

The Slice of the System product (Slice) offered as part of BPA's Subscription Strategy is exempt from the application of CRAC. Slice is exempt from the CRAC because Slice purchasers assume a proportionate share of BPA's financial risks and receive a proportionate share of the benefits of the Federal system. Slice customers bear financial risk through the product design. Under BPA's rate design, certain types of risks are mitigated by tools such as PNRR and CRAC. However, Slice customers assume the risks PNRR and CRAC are designed to remedy, directly through the type of product they purchase. Because Slice customers assume the risks directly, neither the original CRAC nor the proposed modifications in this proposal apply to the Slice product.

Slice purchasers pay a percentage of BPA's actual costs in return for a percentage of system generation. One of the costs Slice purchasers were obligated to assume was a percentage of BPA's augmentation expenses. These costs are referred to as the Inventory Solution in the Slice contract. To determine the Inventory Solution under the Slice contract, BPA calculated the annual average number of MWs necessary to augment the system to meet the total Subscription load. Under their contract, Slice purchasers were expected to bear responsibility for the net cost of the augmentation purchases. The net cost of the Inventory Solution was calculated by multiplying the annual average amount of augmentation by the difference between the market forecast of $28.10/MW for augmentation purchases and the revenue from sale of the augmentation power. This Net Inventory Cost solution also includes the cost of Conservation Augmentation as well as transmission loss underrecovery associated with 1732aMW of augmentation. This net amount was added to the Slice purchasers base rate under the WP–02 ROD for all five years of the rate period. The Net Cost of the Inventory Solution contained in WP–02 is one part of the Net Cost of the Inventory Solution contained in this proposal. A second piece of the Net Cost of the Inventory Solution is the Net Cost of additional augmentation for which the Slice contract provides for a one time MW true up to loads. This increment to the Net Cost identified in WP–02 is determined in exactly the same manner as was used to determine the Net Cost of the Inventory Solution contained in WP–02. When these two Net Costs are added, they then form the baseline from which to determine how much the Net Cost of the Inventory Solution will change, positive or negative, once the assumption of a fixed cost for augmentation of $28.10 is removed. However, because the market forecast of $28.10 is well below current estimates for the market price for power, relying entirely on this mechanism to insure Slice purchasers to pay their pro rata share of the augmentation cost will result in a cost shift to non-slice customers if an adjustment is not made.

The financial impacts of purchasing the unanticipated augmentation in a market where prices are significantly higher and more volatile are; not accounted for in the WP–02 ROD. In this rate proceeding, BPA is proposing changes to the manner in which the augmentation costs are calculated to insure purchasers proportionately share the additional financial risk associated with the increased augmentation requirements, market prices, and market volatility.

Under the revised proposal, BPA would calculate its augmentation costs based upon a combination of actual purchases and an index of market prices. The actual costs of purchases will be calculated after the fact on a monthly basis and will be denoted in dollars per percent of Slice and then be applied to the Slice purchaser's bill in the next month. To calculate the dollar amount, BPA will use the flat annual average augmentation of 2,460aMW as the foundation for this calculation. The 2,460aMW equals the 3,254aMW flat annual augmentation minus augmentation purchases made by August 1, 2000, which are deemed to have been purchased at $28.10, and which amount to 794aMW. To calculate the Slice purchaser's share of the cost, BPA would use the advanced market purchases made by BPA to meet this augmentation requirement. To the extent that BPA also relies upon its own generation or short-term market purchases to meet the augmentation, those costs or avoided costs will also be factored into the charge to Slice purchasers. These costs will be priced at the weighted average of the 50 percent of the firm Dow Jones COB flat price and 50 percent of the firm Mid-Columbia flat price for heavy and light load hours. BPA is proposing to define the baseline Net Inventory Costs as the sum of the Net Inventory Costs included in WP–02 plus the additional Net Inventory Costs associated with the increment in augmentation attributable to the one time MW true up to loads contain in the Slice contract. Slice customers will pay the sum of these Net Inventory Costs in the base Slice rate. The second step in the process will be an after the fact adjustment to the base Slice rate to reflect the actual costs of the augmentation. When the adjustment is greater or less than the Net Inventory Costs in the base Slice rate, there will be a debit or credit on Slice customer monthly bills.

2. IOU Settlement

The Residential Exchange Settlements with regional IOUs provide benefits in the form of both power and cash. The monetary portion of the benefits is calculated based on the difference between the RL or PF-Exchange Subscription rate and BPA's rate case market price forecast. Originally, BPA adopted $28.10/MW as the rate case market forecast for calculation of the monetary benefits. After reconsidering the appropriateness of that number, given the escalating and volatile market now being experienced, BPA is proposing to calculate the financial aspect of the settlements using BPA's $34/MW rate case market forecast for the monetary benefits component of the IOU Settlement. In addition, the financial aspect of the settlement benefits will be exempt from the FB CRAC and LB CRAC.

3. Early Signers

On August 1, 2000, BPA temporarily suspended the signing of any new power contracts, because of the uncertainty created by the projections of increased loads and greater market volatility. Prior to that date, BPA and a number of its customers had already signed new Subscription power contracts for the upcoming rate period that would price power at the PF–02 rate. The timing of the contract signing does not, under BPA's proposal, provide a sufficient basis to exempt these contracts from the application of the three-stage CRAC in this proposal.

4. Change to the DDC Timing

BPA is proposing two changes to the Dividend Distribution Clause (DDC) as it was described in the May 2000 WP–02 Final Proposal. The first change is that the DDC would not be available in the first year (2002) of the rate period. The second change is that BPA intends to conduct the public process by April 1, 2002, rather than by October 2001, to determine how any distribution will be allocated among stakeholders during the rate period. The first $15 million will continue to be allocated to qualifying Conservation and Renewable purposes.

5. The National Environmental Policy Act

BPA has assessed the potential environmental effects of this rate adjustment, as required by the National Environmental Policy Act (NEPA), as part of BPA's Business Plan Environmental Impact Statement (EIS). The analysis includes an evaluation of the environmental impacts of a range of rate design alternatives for BPA's power services and an analysis of the environmental impacts of the rate levels resulting from the rates for such services under the business structure alternatives. BPA's proposal to adjust the WP–02 rate filing falls within the range of alternatives evaluated in the Final Business Plan EIS. Comments on the Business Plan EIS were received outside the formal rate hearing process. The comments have been included in the rate case record and will be considered by the Administrator in making a final decision amending BPA's revisions to the 2002 rate schedules. The Business Plan EIS was completed in June 1995.

Part IV—Public Participation

A. Distinguishing Between ''Participants'' and ''Parties''

BPA will receive comments, views, opinions, and information from ''participants,'' who are defined in the BPA Procedures as persons who may submit comments without being subject to the duties of, or having the privileges of, parties. Participants' written and oral comments will be made part of the official record and considered by the Administrator. Participants are not entitled to participate in the prehearing conference; may not cross-examine parties' witnesses, seek discovery, or serve or be served with documents; and are not subject to the same procedural requirements as parties.

Written comments by participants will be included in the record if they are submitted on or before February 14, 2001. Participants' written views, supporting information, questions, and arguments should be submitted to the address noted in the **ADDRESSES** section. The second category of interest is that of a ''party'' as defined in Rules 1010.2 and 1010.4 of the BPA Procedures. 51 FR 7611 (1986). Parties who intervened in the original phase of this proceeding may participate in any aspect of the amended hearing process.

All written submissions by parties should be directed to:

Anne C. Kunkel, Hearing Clerk—LP–7, Bonneville Power Administration, 905 NE. 11th Avenue, P.O. Box 12999, Portland, OR 97212.

The address for the Hearing Clerk is different from the BPA contact information listed in the **ADDRESSES** section of this notice given the Hearing Clerk is the contact for materials to be submitted to the Administrative Law Judge.

B. Developing the Record

Cross-examination will be scheduled by the Hearing Officer as necessary following completion of the filing of all parties' and BPA's direct cases, rebuttal testimony, and discovery. Parties will have the opportunity to file initial briefs at the close of any cross-examination. After the close of the hearings, and following submission of initial briefs, BPA will issue a Draft ROD that states the Administrator's tentative decision(s). Parties may file briefs on exceptions, or when all parties have previously agreed, oral argument may be substituted for briefs on exceptions. When oral argument has been scheduled in lieu of briefs on exceptions, the argument will be transcribed and made part of the record. The record will include, among other things, the transcripts of any hearings, written material submitted by the participants, and evidence accepted into the record by the Hearing Officer. The Hearing Officer then will review the record, supplement it if necessary, and certify the record to the Administrator for decision.

The Administrator will develop the final adjustments to WP–02 based on the entire record, as amended in this proceeding. The basis for the final adjustments will be described in the Administrator's Final ROD. The Administrator will serve copies of the ROD on all parties and will file the final proposed rate correction, together with the record, with FERC for confirmation and approval. See generally, 18 CFR Pt. 300.

Part V—The Amended 2002 GRSPs

A. Introduction

The following section (Part B below) contains BPA's proposed amendments to BPA's proposed 2002 GRSPs for power rates.

The proposed GRSPs were prepared in accordance with BPA's statutory authority to develop rates, including the Bonneville Project Act of 1937, as amended, 16 U.S.C. 832 (1982); the Flood Control Act of 1944, 16 U.S.C. 825s (1982); the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. 838 (1982); and the Northwest Power Act, 16 U.S.C. 839 (1982).

BPA's 2002 proposed amendments to the GRSPs will supersede BPA's 1996 rate schedules, except for the FPS–96 rate schedule. The FPS–96 rate schedule continues in effect as modified in Docket No. FPS–96R. BPA proposes that its amended GRSPs become effective upon interim approval or upon final confirmation and approval by FERC. BPA currently anticipates that it will request FERC approval of its revised GRSPs effective October 1, 2001.

B. Summary of 2002 Wholesale Power Rate Schedules, 2002 GRSPs, and New 1996 GRSPs

BPA'S Amended 2002 General Rate Schedule Provisions for Power Rates

Index of Amendments to the General Rate Schedule Provisions

Section II: Adjustments, Charges, and Special Rate Provisions

F. Cost Recovery Adjustment Clause (CRAC)
  1. Load-Based CRAC (LB CRAC)
  2. Financial-Based CRAC (FB CRAC)
  3. Safety-Net CRAC (SN CRAC)
H. Dividend Distribution Clause (DDC)
J. Five-Year Flat Block Price Forecast for Monetary Benefit Component of IOU Settlements
S. Slice True-Up Adjustment
X. Slice Augmentation Cost Adjustment (ACA)

F. Cost Recovery Adjustment Clause (CRAC)

There are three sets of conditions under which rate increases under CRAC may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers based on unanticipated augmentation load. The second is the Financial-Based CRAC (FB CRAC), which triggers based on the generation function's forecasted level of accumulated net revenues. The third is the Safety-Net CRAC (SN CRAC), to be implemented if the financial situation falls to a point where the first two components are not sufficient to avoid missing a Treasury payment.

1. Load-Based CRAC (LB CRAC)

A LB CRAC is triggered if the final forecasted augmentation load for the five-year rate period, based on signed contracts, exceeds the amount forecast in the May 2000 WP–02 Final Studies. To the extent the five-year PF augmentation load exceeds that forecast, the CRAC amount will equal that excess load priced at the difference between an assumed flat purchase price of $34/megawatthour (MWh) and the flat PF rate. Forty-six (46) average megawatts (aMW) of additional Industrial Firm Power (IP) load, resulting from Alcoa's inclusion in the compromise approach, will be assessed the difference between $34/MWh and $23/MWh. If the LB CRAC triggers, the CRAC amount will also include the cost of that portion of augmentation originally forecasted in the May 2000 WP–02 Final Studies (1732 aMW) which had not been purchased as of August 1, 2000, priced at the difference between $34/MWh and $28.1/MWh.

The LB CRAC applies to power customers under these firm power rate schedules: Priority Firm Power (PF) Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP–02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL–02), New Resource Firm Power (NR–02), and Subscription purchases under Firm Power Products and Services (FPS). The CRAC does not apply to Pre-Subscription rates, the financial portion of the Residential Exchange settlement, or Slice purchases.

a. *Formula for Calculation of the LB CRAC.* If actual augmentation load for which BPA has signed contracts, as determined in the Amended WP–02 Final Study, exceeds the amount forecast in the May 2000 WP–02 Final Studies (five-year average of 1,732 aMW, or 75,861,600 MWh for the five-year rate period), the LB CRAC triggers, and a CRAC rate increase will go into effect beginning October 2001.

The LB CRAC will be determined as follows:

First, the revenue amount will be calculated in three steps, by the following formula:

(1) The revenue amount reflecting the increase in augmentation required beyond the amount forecasted in the May 2000 Studies is calculated using the following formula:

[($34/MWh minus $19.26/MWh)
times
(difference between PF augmentation load for the five-year rate period, as determined in the Amended WP–02 Final Study, and the augmentation load for the five-year rate period as forecasted in the May 2000 WP–02 Final Studies)]

This equals
($14.74/MWh)
times
(actual augmentation PF load for the five-year rate period, currently expected to be 142,525,200 MWhs, or 3,254 aMW per year,)
minus
75,861,600 MWh).
equals $14.74 times 66,663,600 MWh
equals $982,621,464

(2) The revenue amount reflecting the increased cost of augmentation on the amount forecast in the May 2000 Studies is calculated using the following formula:

[($34/MWh minus $28.1/MWh)
times
(total augmentation load forecast for the five-year rate period in May 2000 WP–02 Final Studies minus total augmentation for the five-year rate period purchased by August 1, 2000)]

This equals
($5.9/MWh)
times
(75,861,600 MWh
minus
34,790,600 MWh)
=$5.9/MWh times 41,071,000 MWh
=$242,318,900

(3) The revenue amount related to the additional 46 aMW of IP load is calculated using the following formula:

[($34/MWh minus $23/MWh)
times
(46 aMW times 8,760 hours times 5 years)]

This equals
($11/MWh)
times 2,014,800 MWh
equals $22,162,800

The total Five-Year Revenue Amount is calculated by adding the results of calculations 1, 2, and 3.

Where the Five-Year Revenue Amount is the amount of additional revenue that an increase in rates under LB CRAC is intended to generate in the rate period.

Where the actual augmentation load is defined as the Amended WP–02 Final Study amount of Subscription load for which BPA has signed contracts for service, which exceeds BPA's forecasted available firm resources.

The Five-Year Revenue Amount is then multiplied by (Non-Slice Load divided by total load subject to LB CRAC plus Slice load) to determine the Pro-Rated Five-Year Revenue Amount. Once the Pro-Rated Five-Year Revenue Amount is determined, that amount will be converted to the LB CRAC Percentage.

The LB CRAC Percentage will be determined by the following formula:

LB CRAC Percentage =
Pro-Rated Five-Year Revenue Amount
Divided by
LB CRAC Five-Year Revenue Basis

Where LB CRAC Revenue Basis is the five-year total forecast of generation revenue from the loads subject to LB CRAC, for the rate period, based on the forecast in the WP–02 Amended Final Proposal.

The LB CRAC Percentage is the percentage increase in each of the firm power rate schedules listed above. This percentage will be applied to energy, demand, and load variance charges subject to the LB CRAC to generate the additional LB CRAC revenue.

b. *Timing of LB CRAC.* The LB CRAC will be assessed in monthly power bills beginning with the bill for delivery of power in October 2001, and continuing through the bill for delivery of power in September 2006.

2. Financial-Based CRAC (FB CRAC)

The FB CRAC is a temporary, upward adjustment to posted power rates for non-Slice Subscription sales if end-of-year Accumulated Net Revenues (ANR) in the generation function are forecasted to fall below a threshold level.

The FB CRAC applies to power customers under these firm power rate schedules: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP–02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL–02), New Resource Firm Power (NR–02), and Subscription purchases under Firm Power Products and Services (FPS). The CRAC does not apply to Pre-Subscription rates, Slice purchases, or the financial portion of any Residential Exchange Settlement.

a. *Formula for Calculation of the FB CRAC.* By mid-February of each FY of the rate period, FY 2002–2006 a forecast of that end-of-year ANR will be completed. If the ANR at the end of any the forecast year falls below the FB CRAC Threshold applicable to that FY, the FB CRAC triggers, and a CRAC rate increase will go into effect beginning the following March.

The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:

FB CRAC Threshold minus forecasted ANR;

or

The annual Maximum Planned Recovery Amount, shown in Table B below, multiplied by (loads subject to FB CRAC divided by [loads subject to FB CRAC plus Slice load]).

Where Revenue Amount is the amount of additional revenue that an increase in rates under FB CRAC is intended to generate during the period that the rate increase is effective;

Where FB CRAC Threshold is the ''trigger point'' for invoking a rate increase under the FB CRAC. The threshold is pre-specified for the end of FY 2002, 2003, 2004, 2005, and 2006 in Table B.

Where ANR is generation function net revenues, as accumulated since 1999, at the end of each of the FY 2002–2006. Audited Actual Accumulated Net Revenues (AANR), confirmed by BPA's independent auditing firm, will be used for FY 1999, 2000, 2001, and any subsequent year for which they are available. Unaudited AANR will be used to the extent audited actuals are not available.

The expected value of a probabilistic forecast of ANR through the end of each FY will be calculated and used to determine if the threshold has been reached, and what the Revenue Amount is. Net revenues for any given FY are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices, with the following two exceptions. First, for purposes of determining if the FB CRAC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP–02 Final Studies. Second, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the CRAC threshold has been reached. Only generation function revenues and expenses, which is to say revenues and forecasted expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the FB CRAC. Accrued revenues and expenses of the transmission function are excluded.

Where Maximum Planned Recovery Amount is the maximum annual amount planned to be recovered through the FB CRAC. Rate increases under the FB CRAC will be due in four equal monthly payments from March through June. All revenues will be paid to BPA prior to June 30 preceding the end of a FY in which the ANR is forecasted to fall below the FB CRAC Threshold.

TABLE B

Fiscal year	FB CRAC threshold (ANR, $ Millions)	Maximum planned recovery amount (Beginning following March)
2002	98	$330 M
2003	41	330 M
2004	7	330 M
2005	7	330 M
2006	7	330 M

Once the Revenue Amount is determined, that amount will be converted to the FB CRAC Percentage. The FB CRAC Percentage is the percentage increase in customers' rate (not including LB CRAC) in each of the firm power rate schedules listed above. This percentage will be applied to generate the additional FB CRAC revenue.

The FB CRAC Percentage will be determined by the following formula:

FB CRAC Percentage =

Revenue Amount
Divided by
FB CRAC Revenue Basis

Where FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC for the FY in which the FB CRAC implementation begins, based on the then most current revenue forecast.

The FB CRAC Percentage is then applied to each customer's forecasted bill for that year (not including LB CRAC), to determine the customer-specific FB CRAC amount. Each customer's FB CRAC amount is then billed to that customer, in four equal amounts, in bills mailed in March through June (for February through May billing periods).

b. *FB CRAC Adjustment Timing.* In February of each year of the rate period, the Administrator will determine whether the expected value of the ANR forecast at the end of that current FY is below the FB CRAC Threshold. If the ANR is forecasted to fall below the FB CRAC Threshold, the Administrator will propose, in February, to assess a cost recovery adjustment increase to applicable rates to be billed in March. The payment is due to BPA prior to June 30.

Each customer will be notified, on or about March 1, of the revenue amount of FB CRAC they will be billed. Each customer will be sent a bill for ¼ of the customer's total FB CRAC obligation for that year, in each of months March, April, May, and June.

c. *FB CRAC Notification Process.* BPA shall follow the following notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post on its electronic information access (World Wide Web) site preliminary, unaudited year-to-date aggregate financial results for generation, including ANR.

By January of each year, BPA shall post on its web site the audited AANR attributable to the generation function for the FY ending September 30.

By May, and August of each year, BPA shall post on its web site an end-of-year forecast of ANR attributable to the generation function.

(2) Notice of FB CRAC Trigger

BPA shall complete and adopt a probabilistic forecast of end-of-year ANR prior to mid-February. BPA shall notify all customers and rate case parties prior to mid-February, in each of the FY 2002–2006, if the expected value of ANR is forecasted to fall below the FB CRAC Threshold for that FY and the extent to which BPA intends to adjust rates under the FB CRAC. Notification will include the audited AANR for the prior FY, the forecast of end-of-year ANR, the calculation of the Revenue Amount, and the FB CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA, as well as the cost management and other risk mitigation steps that BPA has considered and those it is taking. Such data, assumptions and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the FB CRAC implementation process.

Prior to mid-February of any of the FY 2002–2006 in which the ANR is forecasted to fall below the FB CRAC Threshold, BPA staff shall conduct a public forum to explain the ANR forecast, the calculation of the Revenue Amount and the FB CRAC Percentage, and demonstrate that the FB CRAC has been implemented in accordance with the General Rate Schedule Provisions (GRSPs). The forum will provide an opportunity for public comment.

On or about March 1 of any of the FY 2002–2006 in which the ANR is forecasted to fall below the FB CRAC Threshold, the BPA Administrator shall notify all customers to whom the FB CRAC applies of the calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

d. True-up

There will be two opportunities for truing-up the FB CRAC Revenue Amount and each customer's portion of it, based on updated data. When audited actuals are available, in January in the year subsequent to the FB CRAC being implemented, the AANR will be compared to the ANR forecast used to implement the FB CRAC. If the forecasted amount is within $20 million of the AANR (the tolerance), no true-up will be made. If AANR is higher than the forecasted ANR and the difference is greater than the tolerance, BPA will provide refunds of all revenues collected under the CRAC that are in excess of the amount that would be collected using the AANR. Refunds will be in the form of billing credits, shown as reductions on February through May bills. However, if FB CRAC has again triggered at the time of the true-up, no refund will be given. However, the

Revenue Amount for the new FB CRAC will be reduced by the amount over-collected through the prior year FB CRAC.

If AANR is lower than the forecasted ANR, and the difference is greater than the tolerance, BPA will collect from customers the difference in equal installments in the February through May billing period. The total amount collected, however, will not exceed the Maximum Planned Recovery Amount.

BPA also has the option of following the same process to true-up to updated forecasts in June of any year the FB CRAC is implemented.

3. Safety-Net CRAC (SN CRAC)

If the Administrator determines that the financial condition of BPA's generation function has deteriorated to such an extent that even with the implementation of the FB CRAC:

- BPA forecasts a 50 percent or greater probability that it will nonetheless miss its next Treasury payment, or
- BPA has missed a Treasury payment,

this component of the CRAC will be triggered. If the SN CRAC process is triggered, BPA will propose an SN CRAC that, to the extent market and other risk factors allow, achieves a high probability that the remainder of Treasury payments during the rate period will be made timely.

The SN CRAC applies to power customers under these firm power rate schedules: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP–02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL–02), New Resource Firm Power (NR–02), Subscription purchases under Firm Power Products and Services (FPS), and the financial portion of the Residential Exchange Settlement. The CRAC does not apply to Pre-Subscription rates or Slice purchases.

The SN CRAC will be an upward adjustment to posted power rates for Subscription sales through modification of the same parameters used in the FB CRAC. A public process will be conducted to demonstrate the need for such an adjustment, and determine the extent to which the SN CRAC changes could have an amount to be collected, the duration and the timing different from the FB CRAC.

Where Revenue Amount is the amount of additional revenue that an increase in rates under CRAC is intended to generate during the period that the rate increase is effective.

BPA will propose how the Revenue Amount is to be applied to rate schedules to produce an increase in customers rates.

SN CRAC Notification Process

At the time BPA determines that it will not have sufficient funds to make its next payment to Treasury on time and in full, even with full implementation of the FB CRAC, BPA will send notification of the determination to customers and interested parties. BPA will conduct a workshop at which it will identify the amount of shortfall, and present its proposal to achieve a high probability that the remainder of Treasury payments during the rate period will be made timely. The proposal will give priority to prudent cost management and other options that enhance Treasury Payment Probability (TPP) without raising CRAC.

A public process will be conducted. Any interested person shall be provided an adequate opportunity to submit written views, data, questions, and arguments, which shall be made a part of the administrative record. After close of the public process, the Administrator shall make a final decision establishing a CRAC adjustment.

H. Dividend Distribution Clause (DDC)

The DDC is a clause establishing criteria and public process requirements that the Administrator will use to decide whether dividends should be distributed and the dividend amount that should be distributed. The DDC enables BPA to distribute dividends to customers and other stakeholders. The DDC also establishes the mechanism to be used to make a distribution to certain firm power customers.

The DDC applies to power customers under these firm power rate schedules: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP–02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL–02), New Resource Firm Power (NR–02), and Subscription purchases under Firm Power Products and Services (FPS). The DDC does not apply to Pre-Subscription rates, Slice purchases, or the financial portion of any Residential Exchange Settlement under this rate schedule.

The DDC does not apportion, or establish criteria for apportioning, dividends to customers under the above firm power rate schedules or to other customers and stakeholders, other than to qualifying power customers participating in the Conservation and Renewables Discount (C&R Discount).

''Stakeholders'' are groups or public purposes that have a fundamental policy or financial interest in BPA's generation function. These groups include, but are not limited to, customers subject to the posted firm power rate schedules cited above.

1. Formula for the Calculation of the Dividend Distribution Amount

The DDC process will be implemented if audited actual accumulated net revenues for the end of any of the FY 2002–2005 are above the DDC Threshold value.

Actual Accumulated Net Revenues (AANR) are generation function net revenues, as accumulated since 1999, at the end of each of the FY 2002–2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices, with the following two exceptions. For purposes of determining if the DDC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the May 2000 WP–02 Final Studies. The impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the CRAC threshold has been reached. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the DDC; accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent outside auditing firm.

DDC Threshold is the minimum level of AANR that must be realized before a dividend distribution is considered. The DDC Threshold is $388 million for the end of FY 2002, $331 million for the end of FY 2003, and $297 million for the end of FYs 2004, and 2005.

DDC Amount is the aggregate amount that is available to be distributed to customers and stakeholders. The DDC Amount may be equal to zero and will be determined by the following formula:

DDC Amount is the lower of:
AANR − DDC Threshold; or
Cash in excess of that needed to meet the TPP Standard, based on the Five-Year Forecast.

Where the TPP Standard is an 88 percent probability that all planned payments to the U.S. Treasury will be paid on time and in full over the Five-Year Forecast period (or equivalent financial criterion in the event that BPA replaces its TPP Standard); and

Where the Five-Year Forecast is the forecast of accrued revenues and expenses, and the risk analysis and assessment of TPP or any replacement financial criterion, for the current year and subsequent four years that the Administrator prepares and subjects to public review and comment if the DDC Threshold has been met.

The portion of the DDC Amount allocated to power customers (the Power Customers' DDC Amount) will be determined according to a plan to be adopted in a public process BPA will conduct (see section 3 below). The Power Customer DDC Amount will be converted to a percentage (the Power Customer DDC Percentage), which will be applied to all power customer rates subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers.

The Power Customer DDC Percentage will be determined by the following formula:

Power Customer DDC Percentage equals:
Power Customer DDC Amount
Divided by the DDC Revenue Basis

Where DDC Revenue Basis is the total generation revenue for the loads subject to the DDC for the FY in which the DDC implementation begins, based on the then most current revenue forecast.

Each covered power customer will receive a rebate equal to the Power Customer DDC Percentage applied to their total charge for energy, demand and load variance. For any customer or stakeholder entitled to a dividend who is not a power customer, the Administrator will convert the DDC Percentage to a dollar figure.

2. Determination and Timing of a Dividend Distribution

In January of each year of the rate period (FY 2003–2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold: (a) customers and rate case parties will be so notified; and (b) the Administrator will prepare a Five-Year Forecast. On or about March 1, the Administrator will propose to distribute or not distribute dividends. The Administrator will issue a final decision on the proposal on or about April 15.

Dividends distributed to customers are included in energy deliveries beginning May 1, and, for any FY 2003–2005, remain in effect for 12 months i.e., through April 30 of the following year. In the last year of the rate period (FY 2006), the rebate would expire on September 30, 2006.

3. Determining How the Distribution is Allocated

The first $15 million of the DDC Amount, if the DDC Amount exceeds $15 million, or the entire DDC Amount if it equals $15 million or less, will be allocated to qualifying customers' participating in the C&R Discount. The C&R Discount is a rate mechanism designed to encourage incremental conservation and renewable resource development by BPA's power purchasers under PF, IP, RL, and NR rate schedules. See C&R Discount GRSPs, Section II.A.

BPA intends to conduct a separate public consultation process by April 1, 2002, to develop the criteria for allocating any remaining DDC Amount (exceeding the $15 million for the C&R Discount) among customers and stakeholders.)

4. Dividend Distribution Notification Process

BPA shall follow the following notification procedures:

a. *Financial Performance Status Reports.* By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the FY ending September 30.

b. *Notice of DDC Trigger.* On or about January 15 in each of the FY 2003–2006, BPA will notify all power customers and rate case parties if the AANR exceeds the DDC Threshold. (If the December unaudited AANR report for the generation function indicated that the DDC Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified). Notification will include the AANR for the prior FY, the DDC Amount, the calculation of the DDC Amount, and the estimated resulting Power Customer DDC Percentage for each applicable rate schedule. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the DDC implementation process.

(1) On or about March 1 of any of the FY 2003–2006 in which the AANR exceeds the DDC Threshold, the Administrator will post the Five-Year Forecast on BPA's website and will propose to distribute or not distribute dividends. During March, BPA will conduct a public review and comment process on the proposal.

(2) On or about April 15 of any of the FY 2003–2006 in which the AANR exceeds the DDC Threshold, BPA shall notify customers to which the DDC applies of the decision on the proposal, the final calculation of the DDC Amount, the allocation of the DDC Amount, and, if applicable, the resulting level of the Power Customer DDC Percentage to be applied to each applicable firm power rate schedule.

J. Five-Year Flat Block Price Forecast for Monetary Benefit Component of IOU Settlements

The risk-adjusted Five-Year Flat Block Price Forecast is BPA's price estimate of the market price for five-year block purchases for the 2002–2006 period. This forecast is used in calculating the cash component of the proposed settlement of the Residential Exchange Program with regional IOUs as described in BPA's Power Subscription Strategy. The risk-adjusted Five-Year Flat Block Price Forecast is $34 per megawatthour (MWh).

S. Slice True-Up Adjustment

Each year, when the audited actual Slice Revenue Requirement for the previous fiscal year is available, BPA will calculate the final true-up for the previous fiscal year. BPA will calculate the final true-up for the previous fiscal year based on the difference between the Slice Revenue Requirement's audited actual expenses (and credits) and those expenses (and credits) forecasted in the 2002 Power rate case. This true-up will be the True-Up Adjustment Charge and will be applied to the customer's bills. See the Slice Product Costing and True-Up Table (Table D). Adjustments to the MWs used in the Inventory Solution will be trued up using the formula in Table E. Section X contains the methodology BPA will rely on to adjust Inventory Solution costs to fluctuations in BPA's augmentation costs.

X. Slice Augmentation Cost Adjustment (ACA)

a. Application of the ACA

The ACA applies to the Slice Rate in the PF–02 rate schedule.

(1) This adjustment will reconcile the difference between the Slice purchasers pro rata share of BPA's augmentation costs and the forecast of the augmentation costs that is a part of the Slice Revenue Requirement prior to this adjustment. The adjustment will result in a credit or charge to the Slice purchaser's bill as described in the methodology below.

b. For purposes of calculating and applying the ACA, the following definitions will apply:

(1) ''Adjusted Augmentation Costs'' (AAC) means the dollar cost of meeting AAMT separately for the HLH and LLH in the month.

(2) ''Augmentation Amount'' (AAMT) means the total amount of augmentation in flat annual aMWs forecasted by BPA in its Amended ROD for the 2002 rate case to serve public, DSI, IOU, and Preexisting Contracts less augmentation purchases made by BPA prior to August 1, 2000.

(3) ''Augmentation Cost Adjustment'' (ACA) means the adjustment to the slice rate to recognize the difference between the cost of acquiring the AAMT at 28.1, and the adjusted cost basis of acquiring the AAMT that is described herein.

(4) ''Augmentation Pre-Purchase'' (APP) means a contract or other binding obligation entered into by BPA for the delivery of energy and/or capacity necessary to meet AAMT for that month with purchases prior to that month.

(5) ''Baseline Net Augmentation Costs'' (BNAC) means the cost of augmentation for the month that slice customers already bear in the Slice rate to meet AAMT, and for purposes of calculating ACA, shall be determined as follows:

BNAC=(AAMT * 28.1 * Hours in the month)

(6) ''INDEX'' means the weighted average of 50 percent of Firm Dow Jones COB flat and 50 percent of Firm Mid-Columbia Flat for HLH, and separately, for LLH for the month. If one or more of these indexes are abolished or are determined to no longer provide a reasonable measure of market cost, BPA and Slice purchasers shall establish replacement index(s).

(7) ''Net Adjusted Augmentation Cost Calculation'' (NAAC) means the TAAC for the month minus the BNAC for the month

(8) ''Total Cost of Augmentation Pre-Purchases'' (TCAPP) means the cost in dollars for the APP made to meet AAMT for the month.

(9) ''Total Adjusted Augmentation Cost'' (TAAC) means the gross adjusted cost of meeting AAMT for the month as determined below.

c. Frequency of ACA Calculation

The adjustment frequency is monthly during the rate period for each month in the rate period. The first month for which an ACA will be determined will be October 2001 and the last month for which an ACA will be determined is September 2006.

d. Determining APP Quantity and Cost for the Month

BPA will maintain records of APP made to meet AAMT identified in (d) noting the amounts (in MWh's and/or MW's and/or aMW's) for each month by Heavy Load Hour (HLH)) and Light Load Hour (LLH) and the cost. BPA will keep separate tallies of HLH and LLH, and will report these results in an aggregate form for HLH and LLH separately.

e. Calculation of the Adjusted Augmentation Cost (AAC)

These calculations will be separately performed for the HLH in the month and the LLH in the month.

1. If APP for the month is greater than AAMT for the month,

AAC = [(AAMT/APP) * TCAPP]

2. If APP for the month is equal to AAMT for the month,

AAC = TCAPP

3. If APP for the month is less than AAMT for the month,

AAC = [TCAPP] + [(AAMT–APP) * INDEX * Hours]

f. Calculation of Total Adjusted Augmentation Costs (TAAC)

Once a separate AAC has been calculated for the HLH and LLH for the month, these will be summed to determine the TAAC for the month.

g. Calculation of the Net Adjusted Augmentation Cost (NAAC)

NAAC for the month shall be determined as follows:

NAAC = TAAC–BNAC

h. Calculation of ACA

ACA for the month shall be determined as follows:

ACA = NAAC/100

i. Adjusting Customer's Bill

A credit to a customer's bill shall occur if ACA is negative. A debit shall occur if ACA is positive.

The amount of credit or debit to appear on an individual customer's bill shall be determined using the ACA for that month and the customer's slice share.

The resulting dollar adjustment shall appear on the bill as a separate line item on the first bill following the calculation of ACA.

Issued in Portland, Oregon, on November 22, 2000.

Steven G. Hickok,

Acting Administrator and Chief Executive Officer, Bonneville Power Administration.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP00–412–000]

Cross Bay Pipeline Company, L.L.C. and Transcontinental Gas Pipe Line Corporation; Notice of Site Visit

November 22, 2000.

On November 30, 2000, staff from the Office of Energy Projects (OEP) will conduct a pre-certification site visit of the proposed Cross Bay Project at Cross Bay Pipeline Company, L.L.C.'s (Cross Bay) proposed and alternative sites for the Cross Bay Compressor Station in Middlesex County, New Jersey, Representatives of Cross Bay will accompany the OEP staff.

All interested parties may attend the site visit. Those planning to attend must provide their own transportation. For further information on attending the site visit, please contact the Commission's Office of External Affairs at (202) 208–0004.

David P. Boergers,

Secretary.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP99–580–002]

Southern LNG Inc.; Notice of Site Visit

November 22, 2000.

On December 6, 2000, staff from the Office Energy Projects (OEP) will conduct a pre-certification site visit of the proposed Sendout Modification Project at Southern LNG Inc.'s (Southern LNG) existing liquefied natural gas import terminal on Elba Island near Savannah, Georgia. Representatives of Southern LNG will accompany the OEP staff.

All Interested parties may attend the site visit. Those planning to attend must provide their own transportation. For further information on attending the site visit, please contact the Commission's Office of External Affairs at (202) 208–0004.

David P. Boergers,

Secretary.

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