DEPARTMENT OF ENERGY

Bonneville Power Administration

2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment

AGENCY: Bonneville Power Administration (BPA), Department of Energy (DOE).

ACTION: Notice of Proposed Wholesale Power Rates and Proposed Resolution of Certain Transmission-Related Issues.

SUMMARY: BPA requests that all comments and documents intended to become part of the Official Record in this process contain the file number designation WP–02. The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), provides that BPA must establish and periodically review and revise 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 its proposed 2002 wholesale power rates, a proposed methodology for treatment and allocation of inter-business line costs, and a cost allocation proposal for non-Federal transmission for Federal and non-Federal power purchases for BPA's current General Transfer Customers, to be effective on October 1, 2001. The rate case proceedings also include BPA's proposal to revise the Priority Firm Power (PF–96) rate schedule by applying a Targeted Adjustment Charge for Uncommitted Loads, to be effective January 1, 2001.

DATES: Written comments by participants must be received by November 5, 1999, to be considered in the Record of Decision (ROD).

ADDRESSES: Written comments should be submitted to the Manager, Corporate Communications—CK; Bonneville Power Administration; P.O. Box 12999; Portland, Oregon 97212.

FOR FURTHER INFORMATION CONTACT: Mr. Michael Hansen, Public Involvement and Information Specialist, at the address listed above. Interested persons may also call (503) 230–4328 or call toll-free 1–800–622–4519. Information also may be obtained from:

Mr. Allen L. Burns, Group Vice President, Power Business Line—PS–6, P.O. Box 3621, Portland, OR 97208
Mr. Stephen R. Oliver, Bulk Power Marketing—PSB–6, P.O. Box 3621, Portland, OR 97208
Mr. Richard J. Itami, Eastern Power Business Area—PSE, 707 W. Main, Suite 500, Spokane, WA 99201
Mr. John Elizalde, Western Power Business Area—PSW–6, P.O. Box 3621, Portland, OR 97208

Responsible Official: Ms. Diane Cherry, Manager for Power Products, Pricing and Rates, is the official responsible for the development of BPA's wholesale power rates.

SUPPLEMENTARY INFORMATION:

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Part I—Introduction and Procedural Background

Section 7(i) of the Northwest Power Act, 16 U.S.C. 839e(i), requires that BPA's rates be established according to certain procedures. These procedures include, among other things, publication of notice of the proposed rates in the **Federal Register**; one or more hearings conducted as expeditiously as practicable by a hearing officer; public opportunity for both oral presentation and written submission of views; data questions and argument related to the proposed rates; and a decision by the Administrator based on the record. This proceeding is governed by Section 1010.9 of BPA's Procedures Governing Bonneville Power Administration Rate Hearings, 51 FR 7611 (1986) (Procedures). These Procedures implement the statutory section 7(i) requirements. Section 1010.7 of the Procedures prohibits *ex parte* communications.

The Bonneville Project Act, 16 U.S.C. 832, the Flood Control Act of 1944, 16 U.S.C. 825s, the Federal Columbia River Transmission System Act, 16 U.S.C. 838, and the Northwest Power Act, 16 U.S.C. 839, provide guidance regarding BPA ratemaking. The Northwest Power Act requires BPA to set rates that are sufficient to recover, in accordance with sound business principles, the cost of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the FCRPS over a reasonable period of years, and the other costs and expenses incurred by the Administrator. In addition, rates for the Federal Energy Regulatory Commission (FERC)-ordered transmission service, including ancillary services, must satisfy section 212(i) of the Federal Power Act, 16 U.S.C. 824k(i). Such rates must also satisfy the comparability standard for the open access tariff reciprocity compliance requirements of FERC Order 888.[1] The inter-business line and General Transfer Agreement (GTA) issues discussed below will be used to develop ancillary service and transmission rates in the subsequent transmission rate case.

BPA's initial proposed 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions are published in Part V below. The studies addressing the factors used to develop these rates are listed in Part IV and will be available for examination on August 24, 1999, 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 August 24, 1999, from 9 a.m. to 12 p.m., Room 223, 911 NE. 11th, Portland, Oregon.

To request any of the studies by telephone, call BPA's document request line: (503) 230–4328 or call toll-free 1–800–622–4519. Please request the document by its listed title. Also state whether you require the accompanying documentation (these can be quite lengthy); otherwise the study alone will be provided. The studies and documentation will also be available on BPA's website at www.bpa.gov/power/ratecase.

BPA will release its 2002 initial wholesale power rate proposal on August 24, 1999, and expects to publish a final ROD on April 7, 2000. BPA will be conducting a formal evidentiary rate hearing attended by regional parties. Interested parties must file petitions to intervene in order to take part in the formal hearing. A proposed schedule for the formal hearing is stated below. A final schedule will be established by the Hearing Officer at the prehearing conference.

August 24, 1999: BPA files Direct Case/ Prehearing Conference
October 14, 1999: Parties file Direct Cases
November 5, 1999: Close of Participant Comments
December 8, 1999: Litigants file Rebuttal Testimony
January 13, 2000: Cross-Examination
February 10, 2000: Initial Briefs Filed

[1] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs ¶ 31,036 (1996).

February 17, 2000: Oral Argument before the Administrator
March 10, 2000: Draft ROD issued
March 24, 2000: Briefs on Exceptions
April 7, 2000: Final ROD—Final Studies

BPA will also be conducting eight public field hearings in cities throughout the region. Public field hearings are an opportunity for persons who are not parties in the formal rate hearing to have their views included in the official record. Written transcripts will be made at all of the field hearings. The field hearings are scheduled to begin at 6 p.m. Following are the tentative dates and locations for the field hearings. Confirmation of these hearing dates will be made through mailings and public advertising or by calling BPA Corporate Communications at the telephone number listed above. Announcements will also be posted on BPA's wholesale power rate case website at www.bpa.gov/power/ratecase.

September 30, 1999: Idaho Falls, Idaho
October 4, 1999: Pasco, Washington
October 5, 1999: Missoula, Montana
October 6, 1999: Spokane, Washington
October 7, 1999: Everett, Washington
October 12, 1999: Olympia, Washington
October 13, 1999: Eugene, Oregon
October 14, 1999: Portland, Oregon

Part II—Purpose and Scope of Hearing

A. Overview of the Market

The wholesale electricity market facing BPA today is different from 1996, when BPA last set rates, although BPA anticipated that the market would become increasingly competitive. External influences such as the national and state-by-state deregulation of the power markets, changes in market price expectations, and continuing concerns about the environment are factors that BPA must take into account when establishing rates.

In 1996, it appeared that BPA's rates could exceed market prices and BPA was not sure it could sell all its power at rates that would recover its costs. By 2002, however, BPA's rates are anticipated to be lower than market prices through cost cutting and careful management, as well as an expectation that market prices could increase. Thus, customers have now indicated an interest in purchasing more power than BPA can produce from the FCRPS.

Despite customers' changed perceptions of the value of BPA power, BPA's business requirements are fairly constant and are dictated by legislation. BPA is required to sell power at a price that recovers all costs. These costs are determined by a number of factors, including, among other things, the cost of generating power; the costs of protecting, mitigating, and enhancing fish and wildlife; the costs of investing in public purposes; and the costs of repaying the Treasury for the capital investment in the hydro system. BPA has addressed these legislative requirements with policies that implement the statutory directives.

The major goal for many of BPA's policies, as stated in BPA's Subscription Strategy, is to 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. Due to the changing market, BPA must balance the competing demands for its low cost power. Public agency customers, known as preference customers, continue to have first priority to this low cost power. For this group, BPA proposes to sell Subscription power below market, with no increase in the average Priority Firm Power (PF) rate from BPA's 1996 rates. BPA's initial rate proposal also implements the Subscription Strategy plan to offer a combination of power and financial benefits to regional investor-owned utilities (IOUs) for the benefit of their residential and small farm customers. BPA's rate proposal also responds to the viability concerns of BPA's direct service industrial customers (DSIs) by offering power below market prices.

In addition to supplying low cost power to its customer groups, BPA policies also spread the benefits of the FCRPS to other stakeholders. BPA uses its funds to support its share of a wide range of activities designed to address fish and wildlife concerns by keeping open all the options for future fish alternatives. Finally, BPA protects the interests of the U.S. Treasury and Federal taxpayers by maintaining a high probability of making Treasury payments on time and in full.

BPA's major Subscription goal is supported by the other three goals of the Subscription Strategy. The second Strategy goal is to avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions. By avoiding rate increases, BPA believes that it contributes to a stable customer base comprised of all customer groups. A stable customer base leads in turn to a stable revenue stream which enables BPA to cover its share of fish and wildlife and conservation costs in this rate period and in future rate periods. BPA has committed to pursue a number of financial strategies through rates and contracts that will allow it to meet its goal of avoiding rate increases, such as following the recommendations of a regional public process known as the Cost Review (described below) to reduce costs.

The third goal of BPA's Subscription Strategy was to allow BPA to fulfill its fish and wildlife obligations while assuring a high level of Treasury payment. There are a wide range of options currently under discussion for these fish and wildlife obligations. The options have different costs associated with them, so BPA's financial tools include methods to ensure that there will be sufficient money to meet the costs, such as risk mitigation measures in the event that future revenues are not as high as anticipated. BPA measures its ability to meet its obligations by setting an 88 percent probability goal of making its U.S. Treasury payment on time and in full. By setting a high Treasury Payment Probability (TPP), BPA assures that all other obligations are met before the Treasury payment is made.

BPA's Subscription Strategy has a final goal of continuing to support its important role of being a leader in the regional effort to capture the value of conservation and renewable resources. BPA intends to provide market incentives for these and other emerging technologies.

BPA's Subscription goal of spreading the benefits of the FCRPS through low cost power, as well as BPA's other goals, are reflected in all of BPA's actions. The rate case provides only one part of implementing BPA's goals—through rate levels and rate designs. Many actions, such as contract negotiations and setting spending levels, occur outside of the ratemaking process.

BPA has conducted a number of public processes over the last five years to gain public input into how to balance these major goals. Now it is about to start another one, the ratemaking process. Following is a list of the other important public processes that BPA has used to involve its customers and stakeholders in the important decisions of how BPA will continue to provide service to the citizens of the Pacific Northwest.

B. An Overview of the Public Processes

This section describes four major public review processes that BPA has undertaken in the last five years. Many important policy decisions were made in these processes. The ratemaking process is one vehicle to implement some of the decisions made in these other processes.

1. Business Plan Public Review Process

In 1995, BPA prepared a draft and final Business Plan, including a draft and final Environmental Impact

Statement (EIS). In the Business Plan, BPA announced its response to a changing market. For the first time, BPA's costs appeared to exceed market prices, so BPA found itself in a more competitive environment. It responded in 1996 with products and services that were competitively priced and that included more flexible terms. BPA began to change how it sold power, establishing posted prices for core requirements products, while selling other unbundled products and energy services at negotiated prices reflecting the true costs of providing services. The goal of these early changes was to give customers lower prices, stability, and flexible new choices, while giving BPA greater certainty about its expected loads and revenues. Unbundling products allowed customers to pay for only those products and services that they needed. Decisions made during the 1995 Business Plan process will not be revisited in this rate case.

The rate design in the current proposal continues the basic goals of the Business Plan, with some added features designed to allow BPA the flexibility of passing to customers the incremental cost of unanticipated expenses.

2. Cost Review Public Review Process

In September 1997, BPA and the Northwest Power Planning Council initiated a process called the Cost Review of the Federal Columbia River Power System (Cost Review). The primary objective of the Cost Review was to ensure that BPA's long-term power and transmission costs would be as low as possible, consistent with sound business practices, so that BPA could maximize its ability to fully recover costs through power rates that are at or below market prices.

The Cost Review process began with the establishment of a panel of five executives with considerable experience managing large organizations during periods of downsizing and competitive transition. The panel focused on costs to be recovered through power rates for the initial Subscription period, fiscal years (FY) 2002 through 2006. Costs associated with fish and wildlife recovery efforts were excluded from the scope of the Cost Review, while the following costs were recognized as subject to significant change in the rate development process:

- Short-term power purchases,
- Residential Exchange Program,
- General Transfer Agreements,
- Federal interest and depreciation, and
- Inter-business line expenses.

A draft of the panel's recommendations was circulated throughout the region, and public comments were received during a month-long period that included public meetings and briefings with various interest groups. Based on comments received during this public consultation process, the draft recommendations were modified and presented to the Administrator, the region's Governors, the Northwest Congressional delegation, and the U.S. House and Senate Committees on Appropriations in March 1998.

Additionally, both the recommendations and implementation plans were a subject of ''Issues '98,'' a public comment process conducted by BPA in summer 1998. A key purpose of Issues '98 was to decide how the Cost Review recommendations would be implemented.

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. For informational purposes only, the history of the Cost Review and implementation of the final recommendations will be summarized in the Revenue Requirement Study, WP–02–E–BPA–02.

3. Subscription Strategy Public Review Process

As noted previously, one of BPA's goals is to encourage the widest possible diversified use of electric energy while recovering costs. To define this broad concept in greater detail for the post-2001 period, BPA engaged in a multiyear process that culminated in BPA's Subscription Strategy.

In 1996, a regional effort began with the Comprehensive Review of the Northwest Energy System. In December 1996, the Final Report of the Comprehensive Review 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.

A public process to develop a Subscription Strategy began in 1997. This process brought together all the regional stakeholders in an ongoing series of workgroups and meetings. BPA issued a final Subscription Strategy and Record of Decision in December 1998.

The Subscription Strategy provides a marketing policy framework for the power rate case. It reflects agency decisions on equitable distribution of the electric power generated by the FCRPS to BPA's customers within the framework of existing law. Although it did not establish any rates or rate designs, it suggested general rate design approaches to be considered in the formal ratemaking process.

The Subscription Strategy also provided a framework for the bilateral negotiations with each customer that will reflect the specific business relationships between BPA and that customer. Those contracts will be negotiated outside this rate case.

The Subscription Strategy recognized that the FCRPS is a regional resource, limited in size, and valued by the citizens of the Northwest. The Strategy seeks to balance potentially competing demands on the system, as described in the key marketing goals above. It guides the distribution of power among competing demands, while balancing the goals of avoiding PF rate increases, meeting fish and wildlife obligations, and funding public purposes.

After going through an extensive public process, BPA stated in its Subscription Strategy that it planned to offer 1,800 average megawatts (aMW) worth of benefits for the residential and small farm consumers of IOUs while meeting all public agency net firm load requirements. The Strategy also stated that BPA expected to be able to meet all loads that DSI customers asked BPA to serve. This rate case consists of the rates to serve all BPA customers.

4. Fish and Wildlife Obligations Public Review Process

Another important public review process has occurred since BPA's last ratemaking process in 1996. In late 1995, the Clinton Administration and the Northwest Congressional delegation agreed to stabilize BPA's fish and wildlife funding obligations over a six-year period, FY 1996 through FY 2001. In September 1996, the Secretaries of Energy, Commerce, Army and Interior signed a Memorandum of Agreement (MOA) on behalf of five Federal agencies—BPA, the National Marine Fisheries Service (NMFS), the U.S. Army Corps of Engineers, the U.S. Fish and Wildlife Service (USF&W), and the Bureau of Reclamation. The MOA represents a multiagency commitment to stable BPA funding for fish and wildlife through FY 2001.

The MOA divides BPA's financial obligations for fish and wildlife into two major categories: (1) The financial impacts of the system operations called for in the 1995 Biological Opinions on the operation of the FCRPS issued by NMFS and the USF&W, as well as certain other operational measures specified in the MOA; and (2) a commitment of an average of $252 million per year for capital costs, operation and maintenance of fish and wildlife facilities, and implementation of the Northwest Power Planning Council's Fish and Wildlife Program.

In addition, the Administration committed to provide cost-sharing assistance pursuant to section 4(h)(10)(C) of the Northwest Power Act, 16 U.S.C. Section 839b(4)(h)(10)(C), on a permanent basis for BPA's direct fish and wildlife expenses, and also to provide section 4(h)(10)(C) credits for BPA's power purchase costs related to its fish and wildlife programs through FY 2001. The Administration also established a Fish Cost Contingency Fund (FCCF) consisting of U.S. Treasury payment credits associated with section 4(h)(10)(C) that BPA has not yet exercised. The FCCF balance of $325 million in U.S. Treasury payment credits will be available to BPA in the case of low water years and under certain other conditions to defray fish and other water-related costs. Further, the Administration acknowledged that, to the extent necessary, BPA would reduce its build-up of cash reserves in FY 1996–2001. This action could make it more likely that BPA would have to reschedule a portion of its annual U.S. Treasury payments in future years.

In June 1997, all eight Senators representing the Northwest sent a letter to Vice President Gore requesting that the Administration work with the Northwest Congressional delegation and the four Northwest Governors through the Governors' Transition Review Board to develop a proposal for extending the MOA beyond FY 2001 to enable BPA to proceed with a Subscription process for post-FY 2001 power sales. As described above, the Subscription concept was created in 1996, during the year-long Comprehensive Review of the Northwest Energy System. The Comprehensive Review was sponsored by the four Northwest Governors and studied how the region's electricity system should be structured in the deregulated wholesale electricity market.

In the absence of a consensus on a post-FY 2001 fish and wildlife recovery strategy by mid-1998, concerned Federal agencies and regional stakeholders agreed that a strategy and mechanism were needed to establish post-FY 2001 fish and wildlife funding assumptions for Subscription and ratemaking purposes. This strategy is directed at ''keeping the options open'' for future decisions on long-term configuration of the FCRPS, including the potential drawdown of reservoirs behind the four Lower Snake River projects and John Day Dam on the mainstem of the Columbia. Without such a strategy and mechanism, BPA could not proceed with its Subscription process for post-FY 2001 power sales or its FY 2002–2006 power rates process because BPA could not provide the necessary cost certainty to its potential post-FY 2001 power sales customers nor assure adequate funding for fish and wildlife recovery efforts.

The Fish and Wildlife Funding Principles (Principles) were developed in consultation with constituents, customers, other Federal agencies, the Northwest Congressional delegation, and Columbia Basin Tribes in an extensive public involvement process. The parties focused on guidelines for structuring BPA's approach to Subscription and FY 2002–2006 power rates to ensure that BPA could meet its financial obligations, including those for fish and wildlife, given hydroconditions, market prices, fish recovery costs, and other uncertainties. The Principles specify that BPA will take into account the full range of potential fish and wildlife costs, as reflected in 13 long-term alternatives for configuration of the FCRPS, with each alternative assumed to be equally likely to occur.

The Principles also state that BPA will set rates to achieve a high probability that U.S. Treasury payments will be made in full and on time over the five-year rate period, and that BPA will adopt rates and contract strategies that are easy to implement and administer and that will minimize rate impacts on Pacific Northwest power and transmission customers. The contract strategies may include sales of Subscription products on staggered contract terms, a Cost Recovery Adjustment Clause (CRAC) in power sales contracts, and cost-based indexed pricing for some Subscription products.

The Principles also commit the Administration to extend the availability of section 4(h)(10)(C) U.S. Treasury payment credits and any remaining FCCF funds through FY 2006 under the same terms as those established for FY 1996 through FY 2001, and to support BPA's efforts to implement the Cost Review recommendations.

The Principles have been reviewed by the Office of Management and Budget and are consistent with the Administration's principles and priorities. These Principles were published on September 16, 1998, in a document entitled ''Fish and Wildlife Funding Principles for Bonneville Power Administration Rates and Contracts.'' Vice President Gore announced the establishment of the Principles on September 21, 1998.

These Principles differ significantly from the MOA. BPA and the other participants are not establishing a budget for the FY 2002 through FY 2006 period. In fact, final decisions and approvals on a fish and wildlife recovery strategy and funding are not expected during this rate proceeding. Because rates are being set before decisions and approvals are made, the Principles take into account the broad range of potential costs associated with the hydrosystem configuration alternatives under consideration at the time the Principles were adopted. The Principles are intended to ensure that BPA's rates and power sales contracts yield a very high probability of meeting all post-FY 2001 financial obligations, including BPA funding obligations for the fish and wildlife recovery strategy that is eventually adopted.

A number of fish and wildlife initiatives are currently being developed, analyzed, and reviewed in the region. These include: (1) the 1999 decision on long-term configuration of the FCRPS called for in the 1995 NMFS Biological Opinion and the NMFS recovery plan for listed salmon and steelhead; (2) the Columbia Basin Forum ''Four H'' process, which focuses on development of a regional fish and wildlife plan through a broad ecosystem approach that takes into consideration the hydrosystem, habitat, hatcheries, and harvest; (3) the Multi-Species Framework initiated by the Northwest Power Planning Council and NMFS, in consultation with the region's Indian Tribes, to establish a coherent array of scientifically based options for the Columbia Basin; and (4) proposed revisions to the Northwest Power Planning Council's Fish and Wildlife Program. BPA believes that the range of costs associated with the 13 alternatives is sufficiently broad to cover any eventual decision made on potential activities to be undertaken, or any outcome reached through these other processes.

In December 1998, BPA published its implementation plan for the Principles. This document is entitled ''How BPA's Subscription Strategy Implements the Fish and Wildlife Funding Principles.'' See Revenue Requirement Study Documentation, WP–02–E–BPA–02A, Volume 1, Chapter 13.

C. Scope of the 2002 Rate Case

Many of the decisions that guide BPA's marketing policies have been made or will be made in other public review processes. This section provides guidance to the Hearing Officer as to those matters that are within the scope of the rate case, and those that are outside the scope.

1. Spending Levels

As described above, the Cost Review recommendations and BPA's planned implementation of those recommendations have already received extensive public review. Pursuant to section 1010.3(f) of BPA's Procedures, 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 visit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's test period revenue requirement for FYs 2002 through 2006. If, and to the extent, any re-examination of spending levels is necessary, that re-examination will occur outside of the rate case. Excepted from this direction on account of their variable nature, dependency on BPA's rate case models, or timing, are: (1) forecasts of Residential Exchange benefits; (2) forecasts of short-term purchase power costs; (3) capital recovery matters such as interest rate forecasts, scheduled amortization, depreciation, replacements, and interest expense; (4) inter-business line expenses; and (5) General Transfer Agreements.

2. Subscription Strategy

As noted above, the Subscription Strategy has already received extensive public review and was accompanied by a Final ROD in December 1998. BPA's Subscription Strategy states that BPA will negotiate new power sales contracts with the DSIs but make the actual level of service under such contracts contingent on the availability of power remaining after the close of the Subscription window. The Subscription Strategy also notes that BPA was not prepared at the time of issuing the Strategy to make any final decisions regarding augmentation in order to serve DSI load. Since then BPA has decided to propose serving approximately 1,440 aMW of DSI load. BPA does not intend to conduct a separate public process to take comments on this proposal. Therefore, parties to the rate case may raise and discuss any issues regarding BPA's proposal to serve the DSIs, including any issues regarding the potential effects of this proposal on BPA's rates.

BPA's Subscription Strategy also provides that BPA will offer the equivalent of 1,800 aMW of Federal power to regional IOUs for the FY 2002–2006 period as a proposed settlement of the Residential Exchange Program. BPA has recently received a suggestion to increase the amount of power provided to regional IOUs from 1,800 aMW to 1,900 aMW for the FY 2002–2006 period. While the Subscription Strategy accurately reflects BPA's settlement proposal, any decision by BPA to change the amount of power offered to the IOUs will be made outside of this rate case. Parties to the rate case, however, may raise and discuss any issues regarding the potential effects of such an increase on BPA's rates.

BPA has developed the Conservation and Renewables (C&R) Discount over the past year based on public comment. The range of public opinion regarding the discount was discussed in the Subscription ROD. Working from the ROD, BPA has included the following proposal as part of the rate case. The C&R Discount will apply to all customers served under requirements rates including the Priority Firm Power rate (PF), the Industrial Firm Power rate (IP), the New Resource Firm Power rate (NR), the Residential Load Firm Power rate (RL), and Slice. The total eligibility for each customer will equal .5 mills per kilowatthour (kWh) based on Subscription loads. Customers will be accountable for demonstrating compliance with their expenditure target at the end of the contract term. The discount will be applied automatically on each customer's monthly bill. If a dividend is declared, based on better than expected revenues, the first $15 million will be disbursed to customers actively pursuing C&R Discount programs.

Also based on the Subscription ROD, BPA is addressing the following issues outside the rate case. Recommendations for measures that will be eligible for the C&R Discount will be submitted to BPA by the Regional Technical Forum. BPA will go through a separate public process to review and adopt these recommendations before the new rates go into effect. BPA will conduct a separate process in the fall of 1999 to discuss simplified eligibility criteria for small utilities and other administrative details.

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 the ROD for the Strategy.

3. 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 Principles were developed through extensive public involvement and comment processes, and have been adopted as policy at the highest levels of the Administration. The rate proceeding will, however, address implementation of the Principles in the Revenue Requirement Study (including repayment studies and risk mitigation), the Risk Analysis Study, the Loads and Resources Study, and the Wholesale Power Rate Development Study (including rate design, cost allocation, and revenue forecast).

Fish and wildlife issues that will be addressed in this rate proceeding include: (1) how the terms of access to the FCCF are modeled in the rate proposal and their impact on TPP and rates; (2) how section 4(h)(10)(C) credits are modeled in the rate proposal and their impact on TPP and rates; (3) the calculation and treatment of operations and maintenance and capital investment in repayment studies and the revenue requirement; (4) the selection, design, terms and conditions, assumptions, treatment, and impact of planned net revenues for risk, CRAC, indexed power sales contracts, stepped rates, and targeted adjustment charge; (5) the RiskMod, NORM, and Tool Kit model design, operation, inputs and outputs, and use of results; (6) the level of TPP that is targeted, from the range of potential TPP targets established in the Principles; and (7) the design, terms and conditions, assumptions, and treatment of the Dividend Distribution Clause (DDC), including the threshold for triggering a dividend distribution, the conditions under which a dividend is distributed, and the mechanism used to distribute dividends to certain power customers.

Included among the policy decisions, commitments, and assumptions that are not at issue in this rate proceeding are: (1) The Administration's decision to extend the existing terms of access to the FCCF and to roll over the existing formula for calculating section 4(h)(10)(C) credits from the current rate period to FY 2006; (2) the content, merits, or level of costs for the fish and wildlife recovery strategies reflected in each of the 13 alternatives; (3) the decision to include the full range of costs for all 13 alternatives for the purposes of BPA's repayment study, revenue requirement, revenue forecast, and risk management studies and strategies; (4) the TPP goal of 88 percent over the 5-year rate period with a ''floor'' of 80 percent; (5) the policy objective that rates and contracts be designed to position BPA to achieve similarly high TPP post-FY 2006; (6) the incorporation of the full range of costs using the same probabilistic method BPA uses for other cost and revenue uncertainties in its ratemaking; (7) the assumption that all 13 alternatives are equally likely to occur; (8) the assumption that BPA's annual fish and wildlife operations and maintenance costs have an equal probability of falling anywhere within the range of $100 million and $179 million; (9) the adoption of a flexible approach in order to respond to a variety of different fish and wildlife cost scenarios, and in particular, the 35 to 45 percent goal of total post-FY 2001 sales in contract-term lengths of three years or less, in short-term surplus sales, and/or in cost-based indexed sales; and (10) the goals of adopting rates and contract strategies that are easy to implement and administer.

4. Transmission Related Issues

In setting rates for the period beginning October 1, 2001, BPA is bifurcating its general rate proceeding into separate power and transmission rate proceedings. BPA has voluntarily committed to marketing its power and transmission services in a manner modeled after the regulatory initiatives articulated by FERC in Order Nos. 888 and 889.[2] In Order No. 888, FERC directed public utilities regulated under the Federal Power Act to functionally unbundle transmission and ancillary services from their wholesale power services, and to establish separate rates for wholesale generation, transmission, and ancillary services. Establishing BPA's power and transmission and ancillary services rates in separate rate cases is consistent with FERC's unbundling paradigm because it will separately resolve power and transmission issues in the different rate cases.

The proposal for new and revised wholesale power rates, the methodology for the treatment and allocation of inter-business line costs, and the proposed cost allocation for non-Federal transmission costs for the Federal and non-Federal power purchases of GTA customers are discussed below. The Administrator will decide the inter-business line and GTA issues as part of the wholesale power rate case and will not revisit the decision on these issues in the subsequent transmission rate case. In addition, the scope of the wholesale power rate case does not include the merits of the business line separation or BPA's rates for transmission and ancillary services that will be marketed by the Transmission Business Line (TBL). All transmission and ancillary service rates and rate design issues will be addressed in the subsequent transmission rate case. A notice of BPA's transmission and ancillary services rate proposals will be announced and published in the **Federal Register** at a later date.

In BPA's 2002 power rate case, BPA will decide the appropriate treatment of costs that mutually affect both of its power and transmission business lines, or that assess costs from one business line to the other. The treatment of these ''inter-business line'' issues will determine whether the costs are recovered through power, transmission, or ancillary services rates. BPA plans to address in this power rate case: functionalization of corporate overhead costs; treatment of generation-integration and generation step-up transformer costs; determination of the generation input costs or unit costs that will become the basis for certain ancillary services rates; and determination of the costs of generation services used by the TBL, including Remedial Action Schemes and station service.

The other transmission-related issues to be proposed in the power rate case include all GTAs and GTA replacement costs for Federal power deliveries and for non-Federal power deliveries, and PBL responsibility, if any, for Delivery Segment costs. Resolution of the GTA issues for Federal and non-Federal power deliveries will allow GTA customers to make informed power purchase decisions and will affect the level of the power revenue requirement.

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 address those transmission items which are not within the scope of this rate case as noted above.

5. Adjustment to PF–96 Rate: Targeted Adjustment Charge for Uncommitted Loads

This rate case also includes a proposal to establish a charge in the PF–96 rate schedule for customer loads that were uncommitted during the 1996 rate case but return to BPA as firm requirements load prior to September 30, 2001. There are no other changes to the PF–96 rate schedule proposed in this rate case.

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 on any issue regarding the proposed adjustment of the PF–96 rate schedule other than the Targeted Adjustment Charge for Uncommitted Loads.

D. The National Environmental Policy Act

BPA's initial rate proposal falls within the scope of the Final Business Plan EIS, completed in June 1995. The analysis in the EIS includes an evaluation of the environmental impacts of rate design issues for BPA's power products and services. Comments on the Business Plan EIS were received outside the formal rate hearing process, but will be included in the rate case record and considered by the Administrator in making a final decision establishing BPA's 2002 rates.

Part III—Public Participation

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

BPA distinguishes between ''participants in'' and ''parties to'' the hearings. Apart from the formal hearing process, 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 received by November 5, 1999. This date follows the anticipated submission of BPA's and all other parties' direct cases. Written views, supporting information, questions, and arguments should be submitted to BPA's Manager of Corporate Communications at the address listed in the **ADDRESSES** Section of this Notice. In addition, BPA will hold several field hearings in the Pacific Northwest region. Participants may appear at the field hearings and present oral testimony. The transcripts of these hearings will be a part of the record upon which the Administrator makes her final rate decisions.

Persons wishing to become a party to BPA's rate proceeding must notify BPA

[2] Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct (Order 889), FERC Stats, & Regs ¶ 31,035 (1996).

in writing. Petitioners may designate no more than two representatives upon whom service of documents will be made. Petitions to intervene shall state the name and address of the person requesting party status and the person's interest in the hearing.

Petitions to intervene as parties in the rate proceeding are due to the Hearing Officer by 9 a.m. on August 24, 1999. The petitions should be directed to: Christopher Jones, Hearing Clerk—LP, Bonneville Power Administration, 905 NE. 11th Ave., P.O. Box 12999, Portland, Oregon 97212.

Petitioners must explain their interests in sufficient detail to permit the Hearing Officer to determine whether they have a relevant interest in the hearing. Pursuant to Rule 1010.1(d) of BPA's Procedures, BPA waives the requirement in Rule 1010.4(d) that an opposition to an intervention petition be filed and served 24 hours before the prehearing conference. Any opposition to an intervention petition may instead be made at the prehearing conference. Any party, including BPA, may oppose a petition for intervention. Persons who have been denied party status in any past BPA rate proceeding shall continue to be denied party status unless they establish a significant change of circumstances. All timely applications will be ruled on by the Hearing Officer. Late interventions are strongly disfavored. Opposition to an untimely petition to intervene shall be filed and received by BPA within two days after service of the petition.

B. Developing the Record

The record will include, among other things, the transcripts of all hearings, any written material submitted by the parties, documents developed by BPA staff, BPA's environmental analysis and comments accepted on it, and other material accepted into the record by the Hearing Officer. The Hearing Officer then will review the record, will supplement it if necessary, and will certify the record to the Administrator for decision.

The Administrator will develop final proposed rates based on the entire record, including the record certified by the Hearing Officer, comments received from participants, other material and information submitted to or developed by the Administrator, and any other comments received during the rate development process. The basis for the final proposed rates first will be expressed in the Administrator's Draft ROD. Parties will have an opportunity to respond to the Draft ROD as provided in BPA's Procedures. The Administrator will serve copies of the Final ROD on all parties. At the conclusion of the rate proceeding, BPA will file its rates with FERC for confirmation and approval.

BPA must continue to meet with customers in the ordinary course of business during the rate case. To comport with the rate case procedural rule prohibiting *ex parte* communications, BPA will provide necessary notice of meetings involving rate case issues for participation by all rate case parties. Parties should be aware, however, that such meetings may be held on very short notice and they should be prepared to devote the necessary resources to participate fully in every aspect of the rate proceeding. Consequently, parties should be prepared to attend meetings every day during the course of the rate case.

Part IV—Major Studies and Summary of Proposal

A. Summary of Proposed 2002 Wholesale Power Rate Structure

1. List of Proposed 2002 Wholesale Power Rates

BPA is proposing five different rate schedules for its 2002 Wholesale Power Rates. All of these rate schedules are discussed in more detail in Part V of this Notice.

a. PF–02: Priority Firm Power Rate

The PF rate schedule is comprised of three rates: the PF Preference rate, the PF Exchange Program rate, and the PF Exchange Subscription rate.

The PF Preference rate applies to BPA's firm power sales to be used within the Pacific Northwest by public bodies, cooperatives, and Federal agencies. This power is guaranteed to be continuously available. The rate applies to the following products:

Full Service Product
Actual Partial Service Product—Simple
Actual Partial Service Product—Complex
Block Product
Block Product with Factoring
Block Product with Shaping Capacity
Slice Product

The PF Exchange Program rate applies to sales of power to regional utilities that participate in the Residential Exchange Program established under section 5(c) of the Northwest Power Act, 16 U.S.C. Section 839c(c).

The PF Exchange Subscription rate applies to sales of power to regional IOUs that participate in a settlement of the Residential Exchange Program. This proposed settlement was established in BPA's Subscription Strategy and includes a power sale component and a financial component. The Strategy noted that power sales under the settlement might be in the form of ''in lieu'' power sales under section 5(c) of the Northwest Power Act or requirements sales under section 5(b) of the Act. The PF Exchange Subscription rate applies to ''in lieu'' sales under the settlement.

b. RL–02: Residential Load Firm Power Rate

The RL rate applies to sales of power to regional investor-owned utilities that participate in a settlement of the Residential Exchange Program. As noted above, the Subscription Strategy indicated that power sales under the settlement might be in the form of ''in lieu'' power sales under section 5(c) of the Northwest Power Act or requirement sales under section 5(b) of the Act. The Residential Load rate applies to requirements sales under the settlement.

c. NR–02: New Resource Firm Power Rate

The NR rate applies to net requirements power sales to IOUs for resale to ultimate consumers for direct consumption, for construction, test, and start-up, and for station service. NR–02 firm power is also available to public utility customers for serving New Large Single Loads. This rate covers seven products:

New Large Single Loads
Full Service Product
Actual Partial Service Product—Simple
Actual Partial Service Product—Complex
Block Product
Block Product with Factoring
Block Product with Shaping Capacity

d. IP–02: Industrial Firm Power Rate

The IP rate applies to firm power sales to BPA's DSI customers. The IP rate applies to the firm take-or-pay Block Product for DSI customers that purchase under 2002 Industrial Firm Power Contracts. The IP–02 rate includes Targeted Adjustment Charges.

e. NF–02: Nonfirm Energy Rate

The NF rate applies to energy sold under an arrangement that does not have the guaranteed continuous availability of firm power. The rate provides for upward and downward pricing flexibility from an average cost. Any time that BPA has nonfirm energy for sale, any combination of the following rates may apply:

Standard Rate
Market Expansion Rate
Incremental Rate
Contract Rate
Western Systems Power Pool Transactions

End-user Rate

2. Rate Development Issues

a. Inter-Business Line Calculations

BPA is addressing certain inter-business line issues that must be resolved in order to determine BPA's power revenue requirement and to forecast associated revenues. In its power rate case, BPA is proposing: a methodology for functionalizing corporate overhead costs; unit costs for generation inputs for operating reserves and regulation ancillary services; the generation input cost for the reactive ancillary service; and the costs of station service and remedial action schemes needed by the TBL. In addition, BPA is proposing an allocation of generation integration and generation step-up transformer costs to the business lines. BPA does not propose to recover any Delivery Segment costs through wholesale power rates. BPA's proposal for treatment of Delivery Segment costs will be resolved in the separate transmission rate case.

b. Rate Mitigation Costs

The average proposed PF Preference rate is about the same as in 1996. However, due to rate design changes, some utilities will experience a rate increase and some will experience a rate decrease based on their individual usage.

BPA has proposed to mitigate rate impacts in a number of ways. These include modifying the monthly demand charge, capping the Load Variance Charge, and continuing the Low Density Discount. These items are described below. In addition, BPA proposes to have $4 million available each year to mitigate remaining impacts on certain customers.

c. System Augmentation Costs

Under the Subscription Strategy, BPA expects to be obligated to serve more firm load than is forecasted to be produced by the Federal Base System (FBS) under critical water conditions. Additional firm power will be needed to augment the FBS. For ratemaking purposes, this firm power will be defined as FBS replacements. The costs associated with this FBS replacement power will be allocated to power rate pools as specified by the rate directives in the Northwest Power Act.

Power purchases for system augmentation are distinguished from balancing power purchases by their longer duration. Balancing power purchases are shorter-term purchases needed to serve daily and monthly load obligations within the annual load/resource balance. System augmentation purchases are for a year or longer, and are needed on an annual basis to produce an annual load/resource balance.

BPA's initial proposal contains a provision that requires purchasers of the Slice product to pay their share of the net costs of system augmentation purchases. The net costs are the actual costs of the system augmentation purchases minus the revenue BPA derives from selling the equivalent amount of power at posted rates. The initial proposal also frees Slice purchasers from paying for shorter-term balancing purchases. These elements of the Slice product were designed at a time when the amount of purchases necessary to augment the system was anticipated to be relatively small.

The anticipated amount of power necessary to augment the system has increased significantly since Slice was initially proposed. Because of the increased augmentation purchases, the risks associated with having Slice purchasers only obligated to share the net costs of system augmentation may no longer be consistent with the underlying principle of the Slice product that there would be ''no cost shifts.'' BPA intends to examine this issue in the rate case to ensure that having Slice purchasers share only the net costs of system augmentation does not create a cost shift.

d. Exchange Settlement Methodology

The Subscription Strategy proposes a settlement of the Residential Exchange Program with regional IOUs that includes both power and monetary benefits. The total package is valued at 1800 aMW at the RL–02 or PF Exchange Subscription rate. BPA will supply at least 1000 aMW at the RL–02 or PF Subscription rate. In addition, the remaining 800 aMW will be provided either in the form of monetary benefits or as physical power at BPA's discretion. For purposes of the rate case this 800 aMW of benefits will be calculated as the difference between a market forecasted price for power and the RL–02 or PF Exchange Subscription rate.

BPA does not know if the IOUs will accept the proposed settlement. (The IOUs have the choice of accepting this RL settlement or participating in the Residential Exchange Program.) Therefore, rates that will apply to the settlement, the RL–02 and PF Exchange Subscription rates, as well as a rate that will apply to the traditional Residential Exchange Program, the PF Exchange Program rate, must be established in the rate case.

3. Changes in Rate Design

BPA redesigned its rates in BPA's 1996 rate case to send price signals that reflected the market estimated at that time. BPA is generally continuing the same rate design for its 2002 rates, with some changes described below to account for current market and hydro conditions.

The major change that BPA has made in designing its rates is to add a ''Subscription Settlement'' step, which serves as the basis for calculating the RL and PF Exchange Subscription rates and for developing targeted adjustment charges for the IP and PF rates. More detail on this change is described later in this Notice under Rates Analysis Model.

a. Load Variance Charge

In this rate case BPA is eliminating the Load Shaping Charge and replacing it with a Load Variance Charge. The Load Variance Charge covers BPA's cost of standing ready to meet customers' load growth for reasons other than annexation or retail access load gain or loss. In addition, it provides Full and Partial Service purchasers the right to deviate from their monthly forecasted BPA purchases due to weather, economic business cycles, or plant energy consumption. The charge is set at 0.80 mill per kWh and is charged against the customer's Total Retail Load. Further details on these charges are found in the General Rate Schedule Provisions (GRSPs) (Part V of this Notice).

b. Stepped Up Multi-Year (SUMY) Block Charge

An additional adjustment is proposed by BPA to recover the added cost of serving a block purchase that increases over time. This is to compensate BPA for the incremental cost of serving an additional amount of load above first year loads.

c. Monthly Demand and Energy Charges

BPA is proposing to set monthly energy and demand charges for the FY 2002–2006 rate period. BPA's Marginal Cost Analysis shows substantial monthly differentiation in predicted energy rates for this period. In setting monthly charges for energy and demand, BPA is moving away from the six seasonal period energy charges and the annual demand charge used in BPA's 1996 rate case.

d. Demand Adjuster

In addition to the change in the development of the demand charge, BPA is making a change in the measurement of a customer's peak demand. BPA will continue measuring Full Service customers' peak demand coincidental to BPA's generation peak. However, Partial Service customers' demand entitlement is measured on their system peak, and adjusted through a Demand Adjuster to compensate for the different demand billing basis compared to the demand billing basis of a Full Service customer.

e. Stepped Rates

A major change in BPA's proposal is the posting of Stepped Rates. The Rates Analysis Model (RAM) calculates an average five-year rate, however, rates that customers pay will be differentiated between the first three years and the last two years of the rate period. The rates for the FY 2002 to 2004 period will be 0.6 mills per kWh below the average five-year rate. The rates for the FY 2005 to 2006 period will be 0.9 mills per kWh above the average five-year rate. The effective differential is 1.5 mills per kWh.

4. New Adjustments to Rates

BPA is proposing a number of new adjustments and continuing some existing adjustments. These adjustments are listed alphabetically and are discussed in greater detail in Part V of this Notice.

a. Conservation and Renewables (C&R) Discount

BPA has included a C&R Discount in this rate case. In setting power rates, BPA has included the cost of this discount by applying 0.5 mills per kWh to loads served by posted rates and the Slice product. Within the PBL billing process, customers will receive a C&R Discount to encourage investment in qualifying new conservation and renewables. BPA and its customers will reconcile the actual conservation and renewable investments and C&R Discount eligibility. BPA is assumed to remain revenue neutral in this program. While IP–02 rate customers are eligible for the C&R Discount, the discount cannot be used to lower the IP rate below the DSI Floor Rate.

b. Cost Recovery Adjustment Clause (CRAC)

BPA is including a CRAC in its rate proposal as one of the risk mitigation tools intended to address the wide range of financial uncertainty BPA is facing in the FYs 2002–2006 rate period. The CRAC would cause posted power rates to be adjusted upward for one year if actual accumulated net revenues (AANR) fall below a threshold level: -$350 million for FYs 2001 and 2002 and $200 million for FYs 2003, 2004, and 2005. These levels of AANR are equivalent to reserve levels of $300 million for FYs 2001 and 2002, and $500 million for FYs 2003, 2004, and 2005. In the event that AANR falls below the threshold level for any of the years from FYs 2001–2005, rates will be increased for a 12-month period beginning with power deliveries in the following April. (In FY 2006, rates will only be increased for six months, through the end of FY 2006.) The CRAC is intended to generate additional revenue of up to $125 million, $135 million, $150 million, $150 million, and $87.5 million if the threshold levels are crossed for FYs 2001, 2002, 2003, 2004, or 2005, respectively. The CRAC is projected to have an average of about a 12 percent chance of triggering.

c. Cost-Based Indexed IP Rate

BPA is proposing a variable rate for the direct service aluminum companies in this rate filing. It will be a rate that is adjusted higher or lower to reflect the aluminum price forecast. The rate is designed to go no lower than 19 mills per kWh, with an upper ceiling of 28.5 mills per kWh. The variable rate will be designed to yield an average rate of 23.5 mills for those DSI customers that will be offered an Industrial Power Targeted Adjustment Charge (IP TAC) rate of 23.5 mills, and 25 mills for those DSI customers that will be offered an IP TAC rate of 25 mills.

d. Cost-Based Indexed PF Rate

This rate is designed to provide a market based alternative rate to all firm load requirements customers that wish to diversify their power portfolios. Customers can choose to convert their applicable PF rate to a market indexed or floating price adjusted for BPA's risk. The customer and BPA will choose a mutually agreeable reference point for the index, and the index price will be based on a current market forecast of the index selected.

e. Dividend Distribution Clause (DDC)

Because of a wide range of financial uncertainties, there is the potential that net revenues will accumulate in excess of what will be needed to ensure recovery of costs over time. BPA is proposing to distribute "dividends" if an accumulated net revenue threshold is exceeded and if a five-year net revenue forecast and risk analysis show that an 88 percent Treasury Payment Probability would still be met.

The DDC proposes criteria and process requirements that the Administrator will follow in determining the total amount of annual dividends. BPA intends to conduct a separate public consultation process before the beginning of the rate period to establish criteria for apportioning the amount of annual dividends among BPA stakeholders.

f. Excess Factoring Charges

Part of the rate design in this rate case includes the establishment of a Factoring Product and an Excess Factoring Charge. Factoring for purposes of the Core Subscription Products is specifically defined as the BPA service of shaping a given quantity of megawatt-hours among hours during certain periods to follow load. Factoring charges will be applied to Excess Load Factoring that exceeds the benchmark limits. The Factoring Charge is limited to customers that have dispatchable resources and that have purchased the Actual Partial Product or the Block Product with the Factoring Product.

g. Green Energy Premium

The Green Energy Premium (GEP) will be available to customers purchasing firm power. The GEP will be charged when a customer chooses to designate any portion (up to 100 percent) of its Subscription purchase as Environmentally Preferred Power.

The GEP will range from zero to $40/megawatthour depending on the specific products and associated costs selected by each customer.

h. Industrial Power Targeted Adjustment Charge (IP TAC)

BPA is proposing to apply a TAC to all IP sales to cover the incremental costs that it incurs from purchasing power to serve loads beyond the amount of firm inventory in the augmented FBS. It will apply to sales at both 23.5 mills and 25 mills. The IP TAC will prevent the transfer of these incremental costs to other customers. It is designed to recover costs to keep BPA whole, and is not designed to discourage purchases from BPA.

i. Low Density Discount (LDD)

BPA is continuing to offer the LDD to utilities with low system densities, such as rural electric cooperatives with high distribution costs resulting from sparsely populated service areas. The LDD principles, eligibility criteria, and discount calculation table appear in the GRSPs.

j. PF Targeted Adjustment Charge (PF TAC)

The purpose of the PF TAC is to allow BPA the flexibility of passing to customers the incremental cost of unanticipated or additional loads that are not embedded in the posted rates for the FYs 2002–2006 rate period. The Subscription Strategy indicated that BPA would have inventory available during the Subscription window for customers. After the window closes, all ''late signers'' or public utilities with new or annexed load, including retail access load gain or returning load, will be subject to a PF TAC. The PF TAC also applies to requests for requirements service for customer loads previously served by a customer's own resources. If inventory is available to serve the request, the PF TAC is the PF rate. If BPA must buy power to serve the load, an adjustment charge reflecting the differences between PF–02 and BPA's cost to buy power is added to the PF rate.

BPA will provide limited exemptions from the PF TAC for those customers requesting requirements load previously served by renewable resources. In developing the posted rates, BPA is not forecasting that it will receive revenues under the PF TAC.

k. Slice True-Up Adjustment

Under the Subscription Strategy, BPA decided to offer a Slice product. Each year, BPA will calculate the difference between the Slice Revenue Requirement's audited actual expenses and credits and the expenses and credits that are forecast in this rate case. The true-up will be a charge to the Slice customer's bill.

l. Unauthorized Increase Charges for Power Sales

This rate proposal includes separate penalty charges for Unauthorized Increases in Energy and Unauthorized Increases in Demand. These charges will be applied to deliveries that exceed contractual entitlements for energy and demand, respectively. Further details on these charges are found in the GRSPs (Part V of this Notice).

m. Value of Reserves

Section 7(c)(3) of the Northwest Power Act, 16 U.S.C. 839e(c)(3), provides that the Administrator shall adjust rates to the direct service industrial customers ''to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.'' The DSIs may provide two types of reserves: Supplemental Contingency Reserves and Stability Reserves. The Initial Rate proposal assumes that Stability Reserves will be purchased by the TBL and addressed in TBL's transmission rate case.

The PBL is proposing a new approach to procuring Supplemental Reserves in this rate case. The PBL will purchase the most cost-effective Supplemental Reserves or provide those reserves itself. No Supplemental Reserves are explicitly forecasted to be provided by the DSIs in this rate case. Any payment to the DSIs for Supplemental Contingency Reserves will be negotiated within a specified range on an individual customer basis rather than a credit applied to some or all of BPA's DSI load. The range is stated in the IP rate schedule (see Part V of this Notice).

5. Development of IP Rate/7(c)(2) Adjustment

The IP–02 rate applies to firm power sales to BPA's DSI customers, including the firm take-or-pay Block Product for DSIs that purchase power under 2002 Industrial Firm Power contracts. Rates for the DSIs are set according to the rate directives contained in section 7(c) of the Northwest Power Act, 16 U.S.C. 839e(c). Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set ''at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.'' 16 U.S.C. 839e(c)(1)(B). Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's ''applicable wholesale rates'' to its preference customers and the ''typical margins'' included by those customers in their retail industrial rates. 16 U.S.C. 839e(c)(2). Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. 16 U.S.C. 839e(c)(3). This adjustment is typically made through a value of reserves (VOR) credit. As described above, for this rate case BPA is not proposing a uniform VOR credit to be applied against DSI rates. Thus, the DSI rates shall be set equal to the applicable wholesale rate, plus a typical margin, subject to the floor rate test. As a final step in rate design, BPA develops monthly and diurnally differentiated energy charges and monthly differentiated demand charges based on allocated costs and scaled based on the results of BPA's Marginal Cost Analysis.

The typical Industrial Margin is 0.46 mills per kWh. As stated above, a zero VOR credit is being forecast in this rate case. Thus, the net margin of 0.46 mills per kWh is added to the seasonal and diurnal PF energy charges.

Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period ''shall in no event be less than the rates in effect for the contract year ending June 30, 1985.'' 16 U.S.C. 839e(c)(2). Accordingly, a floor rate test is performed to determine if the IP rate has been set at a level below the floor rate. If so, an adjustment is made that raises the DSI rate to recover revenues at the floor rate and credits other customers with the increased revenue from the DSIs. If the DSI rate has been set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP–83 Standard rate charges to test period (FY 2002—2006) DSI billing determinants. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills per kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP–83 rate. Both adjustments are made on a mills per kWh basis.

BPA is conducting separate rate cases for power and transmission. Therefore, BPA has removed all transmission costs from the IP–83 rate to make a power-only floor rate comparison. These calculations result in a DSI floor rate of 20.98 mills per kWh. Because the proposed IP rate revenues are below the floor rate revenues, an adjustment was necessary. Therefore, the IP rate becomes the floor rate.

6. Changes in Methodology

a. AURORA Model

AURORA is a model used to estimate the variable cost of the marginal resource in a competitively priced energy market. In competitive market pricing, the marginal cost of production is equivalent to the market clearing price, which is the basis for determining BPA's bulk power revenues in the rate case.

AURORA models wholesale energy transactions within a competitive market pricing system. AURORA uses a demand forecast and supply cost information to estimate marginal cost. To determine the marginal cost in a given hour, AURORA models the dispatch of electric generating resources in least cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource. Over time, AURORA adds new resources and retires old resources based on the net present value of the resource.

b. Risk Mitigation

This rate proposal implements the TPP standard that all payments to Treasury of the power function be recovered through power rates on time and in full over the 5-year rate period with 88 percent probability. Payments to Treasury are the lowest priority in BPA's priority of payments. For this reason, TPP measures the ability to recover costs in a timely fashion.

BPA has identified and analyzed its power risks and is proposing to implement several risk mitigation tools that, taken together, achieve an 88 percent TPP: access to the Fish Cost Contingency fund; starting FY 2002 financial reserves; a CRAC that adjusts posted rates upward as frequently as each year of the five-year rate period if actual accumulated net revenues attributable to the generation function fall below an accumulated net revenue threshold; and Planned Net Revenues for Risk, a component of the revenue requirement that is added to planned expenses.

c. Rates Analysis Model (RAM)

The RAM has been modified to have two steps. The first is the Rate Design Step, which uses the Northwest Power Act's rate directives to calculate posted rates, including the NR–02 rate and the PF Exchange Program rate. In this first step, BPA calculates rates by: (1) allocating costs to rate pools as noted in the Cost of Service Analysis (COSA); (2) adjusting these results to reflect revenue credits and statutory rate directives; and (3) using the marginal cost of power values to shape the annual costs into energy rates across months and time-of-day. In the second step, the Subscription Step, BPA adjusts the rates calculated from the first step to reflect the Subscription Strategy and to produce Subscription power rates.

7. Adjustment to PF–96: Targeted Adjustment Charge for Uncommitted Loads

The Targeted Adjustment Charge for Uncommitted Loads (TACUL) applies to purchases from BPA to serve customer loads that were uncommitted during the 1996 rate case due primarily to the diversification of customer loads. Uncommitted loads returning to BPA firm power requirements service from January 2001, through to the beginning of the 2002 rate period, will be subject to TACUL. The TACUL will prevent the erosion of reserves that could occur from additional costs of power purchases that may be required to meet customer returned load.

BPA is currently facing an energy deficit during the time period January 2001 to September 2001, and could face even greater deficits should BPA receive additional requests by customers to serve returning uncommitted load. These incremental loads will be charged the PF Preference (PF–96) rate, plus the TACUL, which is an adjustment charge reflecting the difference between the PF–96 rate and BPA's cost to supply this power. BPA will calculate the cost for the TACUL at the time a customer requests power or requests BPA to price power already purchased under this schedule. The TACUL will be finalized prior to signing of the final contract or before initial delivery. The TACUL will expire with the PF–96 rate schedule.

8. Payment of Non-Federal Transmission Costs for GTA Customers' Federal and Non-Federal Power Purchases

BPA's PBL and TBL are proposing to pay the non-Federal transmission cost for customers' Federal and non-Federal power purchases, respectively. PBL's and TBL's proposals are separate and distinct from one another.

PBL proposes to continue existing GTA service to current loads for delivery of Federal power through the FY 2001–2006 rate period. Continuation of GTA service for Federal power deliveries is consistent with BPA's historical practice and helps promote the widespread use of Federal power. The GTA costs associated with delivery of Federal power will be borne by PBL and are estimated to be around $42 million per year through the rate period.

TBL proposes to pay up to $6.5 million annually for non-Federal transmission to allow preference and DSI customers who have historically been served by GTAs to avoid ''pancaked'' transmission rates when serving their loads with non-Federal power. BPA proposes that the forecasted non-Federal transmission cost (up to the cap of $6.5 million) for GTA customers' non-Federal power purchases will be included in cost of the Network segment, or its successor, when it develops its transmission rate proposal. This rate treatment is included in the power rate case to resolve all issues that affect GTA customers and to enable GTA customers to make informed power purchase decisions.

B. Studies in Support of Initial Proposal

The studies that have been prepared to support BPA's 2002 Initial Wholesale Power Rate proposal are described in detail in this section.

Loads and Resources Study and Documentation (Study about 100 pages, documentation about 500 pages)
Revenue Requirement Study and Documentation (Study about 250 pages, documentation about 700 pages)
Risk Analysis Study and Documentation (Study and documentation are combined, approximately 130 pages)
Marginal Cost Analysis Study and Documentation (Study about 50 pages, documentation about 400 pages)
Wholesale Power Rate Development Study and Documentation (Study about 175 pages, documentation about 700 pages)
Section 7(b)(2) Rate Test Study and Documentation (Study about 50 pages, documentation about 350 pages)

1. Loads and Resources Study

The Loads and Resources Study represents the compilation of the load and resource data necessary for developing BPA's wholesale power rates. The Study has three major interrelated components: (a) BPA's Federal system load forecast; (b) BPA's Federal system resource forecast; and (c) the Federal system load and resource balances.

The Federal system load forecast is composed of customer group sales forecasts for public utilities and Federal agencies, DSIs, IOUs, and other BPA contractual obligations.

The Federal system resource forecast includes power generated by both Federal and non-Federal hydroprojects, return energy associated with BPA's existing capacity-for-energy exchanges, contracted resources, and other BPA hydrorelated contracts. The Federal system hydroresource estimates are derived from a hydroregulation study that estimates generation under 50 water conditions using the operating provisions of the Pacific Northwest Coordination Agreement. The seasonal shape and magnitude of the Federal system hydro generation depends on availability of all regional resources and coordination of those resources to meet regional loads.

The projections of Federal system resources are compared with projected Federal system firm loads for each month of Operating Years 2002–2007 (August 2001–July 2007) under 1937 water conditions. The resulting load and resource balances yield the firm energy surplus or deficit of the Federal system resources. Similarly, firm capacity surpluses and deficits are determined for the same period.

2. Revenue Requirement Study

The purpose of the Revenue Requirement Study is to establish the level of revenues from wholesale power rates necessary to recover, in accordance with sound business principles, the FCRPS costs associated with the production, acquisition, marketing, and conservation of electric power. Power revenue requirements include recovery of the Federal investment in hydrogeneration, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest (formerly known as the Supply System); other purchase power expenses, such as short-term power purchases; power marketing expenses; cost of transmission services necessary for the sale and delivery of FCRPS power; and all other power-related costs incurred by the Administrator pursuant to law.

Cost estimates reflect implementation of Cost Review recommendations, the Principles, and certain components of the Subscription Strategy. No change in repayment policy or practice is proposed. The repayment study reflects actual implementation of the Appropriations Refinancing Act and a number of updates to actual and projected new repayment obligations. All new capital investments are assumed to be financed with debt or appropriations. The study includes a substantial level of planned net revenues to mitigate financial risk. This risk mitigation tool, in combination with other risk mitigation tools such as starting financial reserves, CRAC, and access to the FCCF, is designed to achieve the 88 percent TPP standard. The adequacy of projected revenues to recover test period revenue requirements and to meet repayment period recovery of the Federal investments is tested and demonstrated for the generation function.

3. Risk Analysis Study

The Risk Analysis Study evaluates both operational and non-operational risks. The portion addressing operational risks evaluates impacts of economic and generation resource capability variations on BPA's ability to meet its annual U.S. Treasury payment during the rate test period. The portion addressing non-operational risks evaluates the impacts of uncertainties in cost projections in the revenue requirement. The results are used to support the amount of planned net revenues for risk that are included in the revenue requirement. The risk variations are tested through the use of several risk simulation models including RiskMod, which quantifies net revenue risk; RevSim, a revenue and expense estimation model; RiskSim, a data management model; and the Non-Operating Risk Model (NORM), which quantifies the non-operating risks. The Risk Analysis, through the use of these models, captures the range of ordinary risks that BPA could reasonably expect to face during the rate test period. The models do not attempt to capture and measure the effects of extraordinary and/or unquantifiable risks such as State or Federal electricity deregulation legislation.

The Risk Analysis Study, with input from the Marginal Cost Analysis (MCA), is also used for estimating purchase power expense and secondary revenues.

4. Marginal Cost Analysis (MCA)

The MCA estimates the hourly variable cost of the marginal resource for transactions in wholesale energy market. The specific market used in this analysis is at the Mid-Columbia trading hub in the State of Washington.

The MCA is used for two purposes in the BPA rate case. First, the MCA is the basis for approximating the prices BPA may experience in the bulk power market. The MCA estimates are therefore used to inform, but not to directly set, the price used in BPA's bulk revenue forecast. Second, the MCA represents BPA's marginal cost in acquiring new energy, or the opportunity cost BPA may see in selling wholesale energy. The MCA is therefore used in rate design to send market based price signals.

The MCA uses a production cost model, AURORA, to estimate a market clearing price for wholesale energy. The fundamental theory behind this model is based on a competitive wholesale energy pricing structure. The model dispatches resources in a least cost order to meet a specified demand. Short-term prices are set at the variable cost of the marginal generator. Long-term capital investment decisions are based on economic profitability in an unregulated environment.

5. Wholesale Power Rate Development Study

The Wholesale Power Rate Development Study (WPRDS) is the primary source for details of the rates, reflecting the results of all the other studies. It documents the Rates Analysis Model and designs rates for BPA's wholesale power products and services. The WPRDS documents the development of Slice costs; the development and forecast of inter-business line revenues and costs; the development of charges for demand, load variance, unauthorized increase charges, and excess factoring charges, and the development of the three and two year rates. The end results of the WPRDS are the wholesale power rate schedules.

6. Section 7(b)(2) Rate Test Study

Section 7(b)(2) of the Northwest Power Act directs BPA to assure that the wholesale power rates effective after July 1, 1985, to be charged its public body, cooperative, and Federal agency customers (the 7(b)(2) Customers) for their general requirements for the rate test period, plus the ensuing four years, are no higher than the costs of power to those customers would be for the same time period if specified assumptions are made. The effect of the rate test is to protect the 7(b)(2) Customers' wholesale firm power rates from certain costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the 7(b)(2) Customers to other rate classes. The Section 7(b)(2) Rate Test Study describes the application and results of the Section 7(b)(2) Implementation Methodology.

The Section 7(b)(2) rate test triggers in this proposal, causing costs to be reallocated in the test period. The PF Preference rate applied to the general requirements of the 7(b)(2) Customers has been reduced by the 7(b)(2) amount while other rates, including the PF Exchange Program rate applied to customers purchasing under the Residential Exchange Program, have been increased by an allocation of the 7(b)(2) amount.

Part V—2002 Wholesale Power Rate Schedules

A. Introduction

BPA's 2002 Wholesale Power Rate Schedules cover five different rates:

PF–02: Priority Firm Power Rate
RL–02: Residential Load Firm Power Rate
NR–02: New Resource Firm Power Rate
IP–02: Industrial Firm Power Rate
NF–02: Nonfirm Energy Rate

The following section (Part B below) contains BPA's proposed 2002 wholesale power rate schedules, BPA's proposed 2002 GRSPs for power rates, and the new 1996 GRSP for the Targeted Adjustment Charge for uncommitted loads.

The proposed wholesale power rate schedules 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 wholesale power rate schedules and the GRSPs associated with those rate schedules 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 wholesale power rate schedules, including the GRSPs associated with these rate schedules, 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 rates effective October 1, 2001.

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

Schedule PF–02

Section I. Availability

This schedule is available for the contract purchase of Firm Power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. Rates in this schedule are in effect beginning October 1, 2001, and are available for purchase under requirements Firm Power sales contracts for a three or five-year period. The Slice Product is only available for public bodies and cooperatives. Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Utilities participating in settlement of the Residential Exchange Program may purchase Priority Firm Power pursuant to their Subscription settlement agreement. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the five-year rates listed in this rate schedule in addition to applicable transmission charges.

Sales under the PF Exchange Subscription rate will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate ''Benefits of the Federal Columbia River Power System (FCRPS)'' to describe the amount of benefits each consumer receives. Only the block product is available under this rate schedule.

This rate schedule supersedes the PF–96 rate schedule, which went into effect October 1, 1996. Sales under the PF–02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). Products available under this rate schedule are defined in the 2002 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

Section II. Rates Tables

The rates in this section apply to PF products. The PF Exchange Program rates and the PF Exchange Subscription rates are shown in Section III.

A. Demand Rate

1. Monthly Demand Rate for FY 2002 Through FY 2006

1.1 Applicability

These rates apply to customers purchasing Firm Power for three or five years. These rates are also used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable months	Rate (kW-mo)
January	$2.14
February	2.06
March	1.96
April	1.37
May	1.32
June	1.69
July	2.12
August	2.44
September	2.28
October	1.90
November	2.31
December	2.40

B. Energy Rate

1. Monthly Energy Rates for FY 2002 Through FY 2004

1.1 Applicability

These rates apply to customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH Rate (mills/kWh)
January	19.06	13.45
February	17.95	12.84
March	17.18	12.09
April	11.64	8.55
May	11.21	7.02
June	14.51	8.61
July	18.85	15.60
August	29.24	19.23
September	20.09	19.40
October	16.68	13.35
November	20.56	17.77
December	21.40	17.67

2. Monthly Energy Rates for FY 2005 Through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH Rate (mills/kWh)
January	20.56	14.95
February	19.45	14.34
March	18.68	13.59
April	13.14	10.05
May	12.71	8.52
June	16.01	10.11
July	20.35	17.10
August	30.74	20.73
September	21.59	20.90
October	18.18	14.85
November	22.06	19.27
December	22.90	19.17

3. Monthly Energy Rates for FY 2002 Through FY 2006

3.1 Applicability

These rates are used to implement the Pre-Subscription Contracts. These rates are also available to customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH Rate (mills/kWh)
January	19.66	14.05
February	18.55	13.44
March	17.78	12.69
April	12.24	9.15
May	11.81	7.62
June	15.11	9.21
July	19.45	16.20
August	29.84	19.83
September	20.69	20.00
October	17.28	13.95
November	21.16	18.37
December	22.00	18.27

C. Load Variance Rate

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.8 mills/kWh.

D. Slice Rate

The monthly rate for the Slice Product is $1,381,390 per 1 percent of the Slice System.

Section III. PF Exchange Rate Tables

The rates in this section apply to sales under the Residential Exchange Program and the Subscription settlements of the Residential Exchange Program.

A. Demand Rate

1. Monthly Demand Rate for FY 2002 Through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program and to customers purchasing power for all five years of the rate period under Subscription settlements of the Residential Exchange Program.

1.2 Rate Table

Applicable months	Rate kW-mo
January	$2.14
February	2.06
March	1.96
April	1.37
May	1.32
June	1.69
July	2.12
August	2.44
September	2.28
October	1.90
November	2.31
December	2.40

B. Energy Rate

1. PF Exchange Program Energy Rates for FY 2002 Through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program.

1.2 Rate Table

Applicable months	Energy rate mills/kWh
January	30.11
February	28.67
March	27.52
April	19.68
May	18.14
June	22.80
July	31.49
August	45.01
September	35.08
October	27.78
November	34.58
December	35.43

2. PF Exchange Subscription Energy Rates for FY 2002 Through FY 2006

2.1 Applicability

These rates apply to eligible customers purchasing power under Subscription settlements of the Residential Exchange Program for all five years of the rate period.

2.2 Rate Table

Applicable months	HLH Rate mills/kWh	LLH rate mills/kWh
January	19.66	14.05
February	18.55	13.44
March	17.78	12.69
April	12.24	9.15
May	11.81	7.62
June	15.11	9.21
July	19.45	16.20
August	29.84	19.83
September	20.69	20.00
October	17.28	13.95
November	21.16	18.37
December	22.00	18.27

C. Load Variance Rate

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV.H below. The rate for Load Variance is 0.8 mills/kWh.

Section IV

The rates described above apply to the following:

Section IV.A. Full Service Product
Section IV.B. Actual Partial Service Product—Simple
Section IV.C. Actual Partial Service Product—Complex
Section IV.D. Block Product
Section IV.E. Block Product with Factoring
Section IV.F. Block Product with Shaping Capacity
Section IV.G. Slice Product
Section IV.H. Customers who purchase under the Residential Exchange Program or Subscription settlements of the Residential Exchange Program

1. Priority Firm Exchange Program Power
2. Priority Firm Exchange Subscription Power

A. Full Service Product

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Measured Demand on the Generation System Peak as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The Purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

B. Actual Partial Service Product—Simple

Purchases of the core Subscription Actual Partial Service Product—Simple are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

(the Purchaser's Demand Entitlement *multiplied by* a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The Purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

C. Actual Partial Service Product—Complex

Purchases of the core Subscription Actual Partial Service Product—Complex are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

(The Purchaser's Demand Entitlement *multiplied by* a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The Purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP Section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

D. Block Product

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Demand Entitlement as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY).	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

E. Block Product With Factoring

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

(The Purchaser's Demand Entitlement *multiplied by* a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY).	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

F. Block Product With Shaping Capacity

Purchases of the core Subscription Block Product with Shaping Capacity *are subject to the charges specified below.*

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Demand Entitlement as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY).	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

G. Slice Product

Purchases of the Subscription Slice Product are limited to Public Body Customers and are subject to the charges specified below.

1. Slice Product Charge

The charge for the Slice Product will be:

The elected Slice Percentage expressed as a decimal (.01 = 1%) *multiplied by* 100 *multiplied by* the Slice Rate in Section II.D.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount.	II.A.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Low Density Discount	II.P.
Slice True-Up Adjustment	II.R.
Unauthorized Increase Charge	II.V.

H. Customers Who Purchase Under Residential Exchange Program or Subscription Settlements of the Residential Exchange Program

The PF Exchange rates include: (1) the PF Exchange Program rate; and (2) the PF Exchange Subscription rate.

1. Priority Firm Exchange Program Power

This PF Exchange Program rate applies to the traditional implementation of the Residential Exchange Program.

a. Priority Firm Exchange Program Power Charges

1.1 Demand Charge

The charge for Demand will be:

(The Purchaser's Billing Demand, which is calculated by applying the load factor, determined as specified in the Residential Exchange Program agreement, to the Billing Energy for each billing period) *multiplied by* the Demand Rate from Section III.A.

1.2 Energy Charge

The monthly charge for energy will be:

(The Purchaser's Billing Energy, which is the energy associated with the utility's residential load for each billing period computed in accordance with the provisions of the Purchaser's Residential Exchange Program agreement) *multiplied by* the Energy Rate from Section III.B.1.

1.3 Load Variance Charge

The charge for Load Variance is embedded in the energy charge.

b. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services under the NT rate schedule or its successor.

Customers purchasing under this rate schedule are charged for Load Regulation under the applicable charge established by the TBL or its successor.

c. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

2. Priority Firm Exchange Subscription Power

This PF Exchange Subscription rate applies to sales under section 5(c) of the Northwest Power Act to investor-owned utilities (IOU) that participate in a settlement of the Residential Exchange Program as described in BPA's Subscription Strategy.

a. Priority Firm Exchange Subscription Power Charges

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Contract Demand *multiplied by* the Demand Rate from Section III.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Contract Energy *multiplied by* the HLH Energy Rate from Section III.B.2.
(2) The Purchaser's LLH Contract Energy *multiplied by* the LLH Energy Rate from Section III.B.2.

1.3 Load Variance Charge

Not applicable.

b. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

Section IV. Transmission

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.1.

Schedule RL–02

Residential Load Firm Power Rate

Section I. Availability

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest. The Residential Load (RL) Firm Power Rate is available to investor-owned utilities (IOUs) under net requirement contracts for resale to ultimate residential consumers for direct consumption. Further, in order to purchase under this rate, the IOU must agree to waive its right to request benefits under section 5(c) of the Northwest Power Act for the term of the contract. Each IOU will be able to purchase a specified amount of Firm Power at the RL–02 rate. Additional sales of requirements power to IOUs will be made at the NR–02 rate.

The product will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate ''Benefits of the Federal Columbia River Power System (FCRPS)'' to describe the amount of benefits each consumer receives.

Rates in this schedule are available for purchases under requirements sales contracts for a five-year period. Only the block product is available under this rate schedule. Sales under this schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

Section II. Rates Tables

The rates for the RL Firm Power product are identified below.

A. Demand Rate

1. Monthly Demand for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for five years.

1.2 Rate Table

Applicable months	Rate (kW-mo)
January	$2.14
February	2.06
March	1.96
April	1.37
May	1.32
June	1.69
July	2.12
August	2.44
September	2.28
October	1.90
November	2.31
December	2.40

B. Energy Rate

1. Monthly Energy Rates for FY 2002 Through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH rate (mills/kWh)
January	19.66	14.05
February	18.55	13.44
March	17.78	12.69
April	12.24	9.15
May	11.81	7.62
June	15.11	9.21
July	19.45	16.20
August	29.84	19.83
September	20.69	20.00
October	17.28	13.95
November	21.16	18.37
December	22.00	18.27

C. Load Variance Rate

Not applicable.

Section III. Billing Factors and Adjustments

Eligible customers purchasing power under a contract implementing Subscription settlements of the Residential Exchange Program are subject to the charges specified below.

1. Residential Load Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Contract Demand multiplied by the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Contract Energy multiplied by the HLH Energy Rate from Section II.B; and

(2) The Purchaser's LLH Contract Energy multiplied by the LLH Energy Rate from Section II.B.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

Section IV. Transmission

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale.

Schedule NR–02

New Resource Firm Power Rate

Section I. Availability

This schedule is available for the contract purchase of Firm Power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOU) under net requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load placed on BPA that is attributable to the NLSL will be billed under this rate schedule.

Rates in this schedule are available for purchases under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contract), for a three or five-year period. Products available under this rate schedule are defined in BPA's 2002 General Rate Schedule Provisions (2002 GRSPs).

This rate schedule supersedes the NR–96 rate schedule, which went into effect October 1, 1996. Sales under the NR–02 rate schedule are subject to BPA's 2002 GRSPs and billing process.

Section II. Rates Tables

The rates in this section apply to NR products.

A. Demand Rate

1. Monthly Demand Rate for FY 2002 Through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for three or five years.

1.2 Rate Table

Applicable months	Rate (kW-mo)
January	$2.14
February	2.06
March	1.96
April	1.37
May	1.32
June	1.69
July	2.12
August	2.44
September	2.28
October	1.90
November	2.31
December	2.40

B. Energy Rate

1. Monthly Energy Rates for FY 2002 Through FY 2004

1.1 Applicability

These rates apply to eligible customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH rate (mills/kWh)
January	40.75	29.41
February	38.50	28.19
March	36.96	26.68
April	25.76	19.52
May	24.88	16.41
June	31.56	19.64
July	40.34	33.76
August	61.32	41.09
September	42.83	41.44
October	35.94	29.22
November	43.78	38.15
December	45.47	37.95

2. Monthly Energy Rates for FY 2005 Through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for eligible customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH rate (mills/kWh)
January	42.25	30.91
February	40.00	29.69
March	38.46	28.18
April	27.26	21.02
May	26.38	17.91
June	33.06	21.14
July	41.84	35.26
August	62.82	42.59
September	44.33	42.94
October	37.44	30.72
November	45.28	39.65
December	46.97	39.45

3. Monthly Energy Rates for FY 2002 Through FY 2006

3.1 Applicability

These rates apply to eligible customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH rate (mills/kWh)
January	41.35	30.01
February	39.10	28.79
March	37.56	27.28
April	26.36	20.12
May	25.48	17.01
June	32.16	20.24
July	40.94	34.36
August	61.92	41.69
September	43.43	42.04
October	36.54	29.82
November	44.38	38.75
December	46.07	38.55

C. Load Variance Rate

The Load Variance rate for FY 2002 through FY 2006 is applicable to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

Section III. Billing Factors, and Adjustments for Each NR Product

This rate schedule contains seven subsections, corresponding to the products to which this rate schedule applies. The following seven products are available to serve NLSLs, or other loads served at the NR–02 rate.

Section III.A. New Large Single Load
Section III.B. Full Service Product
Section III.C. Actual Partial Service Product—Simple
Section III.D. Actual Partial Service Product—Complex
Section III.E. Block Product
Section III.F. Block Product with Factoring
Section III.G. Block Product with Shaping Capacity

A. New Large Single Load (NLSL) Service Product

Purchases of New Resource Firm Power to serve a NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:

The NLSLs Demand Entitlement as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

(1) The NLSLs HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.
(2) The NLSLs LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The NLSLs Measured Energy for the billing period as specified in the contract *multiplied by* the Load Variance Rate from Section II.C.

If the customer is already paying the Load Variance Charge on the NLSL load through this or another rate schedule, this charge does not apply.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

B. Full Service Product

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's Measured Demand on the Generation System Peak as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied* by the HLH Energy Rate from Section II.B.
(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The Purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

C. Actual Partial Service Product—Simple

Purchases of the core Subscription Actual Partial Service Product—Simple are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:

(The Purchaser's Demand Entitlement *multiplied by* a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.

(2) The purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

D. Actual Partial Service Product—Complex

Purchases of the core Subscription Actual Partial Service Product—Complex are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:

(The Purchaser's Demand Entitlement *multiplied* by a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:

The Purchaser's Total Retail Load for the billing period *multiplied by* the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

E. Block Product

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:

The Purchaser's Demand Entitlement as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

F. Block Product With Factoring

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:

(the Purchaser's Demand Entitlement *multiplied by* a Demand Adjuster) as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

G. Block Product With Shaping Capacity

Purchases of the core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:

The Purchaser's Demand Entitlement as specified in the contract *multiplied by* the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract *multiplied by* the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

Section IV. Transmission

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale. Regulation and Frequency Response may have to be purchased for NLSLs.

IP–02

Industrial Firm Power Rate

Section I. Availability

This schedule is available, in conjunction with the IPTAC, to BPA's direct service industrial (DSI) customers for Firm Power to be used in their industrial operations. DSIs that purchase power under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contracts), are eligible to purchase under this rate schedule for up to a five-year period.

This rate schedule supersedes the IP–96 rate schedule, which went into effect October 1, 1996. Sales under the IP–02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

Section II. Rates Tables

The rates for the IP Firm Power product are identified below.

A. Demand Rate for All IP/IPTAC Products

1. Flat Rate Demand for FY 2002 through 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

Applicable months	Rate (kW-mo)
January	$2.14
February	2.06
March	1.96
April	1.37
May	1.32
June	1.69
July	2.12
August	2.44
September	2.28
October	1.90
November	2.31
December	2.40

B. Energy Rate

1. Monthly Energy Rates for FY 2002 Through FY 2006

1.1 Applicability

These energy rates are to be combined with one of the two IP Targeted Adjustment Charges specified in Section 2.2 or 3.2 below.

1.2 Rate Table

Applicable months	HLH rate (mills/kWh)	LLH rate (mills/kWh)
January	21.49	15.87
February	20.37	15.27
March	19.61	14.52
April	14.07	10.98
May	13.63	9.44
June	16.93	11.04
July	21.28	18.03
August	31.66	21.65
September	22.51	21.83
October	19.10	15.78
November	22.99	20.20
December	23.82	20.10

2. Monthly Energy Rates for FY 2002 Through FY 2006 for IPTAC (23.5 mills)

2.1 These rates apply to the eligible customers purchasing power under this rate schedule for all five years of the rate period.

2.2 A charge of 2.02 mills shall be added to each IP energy rate in the Rate Table in 1.2 above.

3. Monthly Energy Rates for FY 2002 Through FY 2006 for IPTAC (25.0 mills)

3.1 These rates apply to the eligible customers purchasing power under this rate schedule for all five years of the rate period.

3.2 A charge of 3.52 mills shall be added to each IP energy rate in the Rate Table in 1.2 above.

C. Load Variance Rate

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

Section III. Billing Factors and Adjustments for Each IP Product

This rate schedule contains two subsections, corresponding to the products to which this rate schedule applies. Only the firm take-or-pay Block Product is available under these rate schedules.

SECTION III.A. DSI Customers Who Purchase Under 2002 Industrial Firm Power (IP) Contracts

SECTION III.B. DSI Customers Who Purchase Under 2002 Industrial Firm Power Targeted Adjustment Charge (IPTAC) Contracts

A. DSI Customers Who Purchase Under 2002 Industrial Firm Power (IP) Contracts

Purchases of power under a 2002 IP contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's monthly Contract Demand *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

The Total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's monthly HLH Contract Energy *multiplied by* the HLH Energy Rate from Section II.B; and

(2) The Purchaser's monthly LLH Contract Energy *multiplied by* the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewable Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Rate Melding	II.Q.
Supplemental Contingency Reserves Adjustment	II.T.
Unauthorized Increase Charge	II.V.

B. DSI Customers Who Purchase Under 2002 Industrial Firm Power Targeted Adjustment Charge (IPTAC) Contracts

Purchases of power under a 2002 IPTAC contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:

The Purchaser's monthly Contract Demand *multiplied by* the Demand Rate from Section II.A.

1.2 Energy Charge

Energy charges will be calculated pursuant to the GRSPs IPTAC at the time of contract negotiations.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, charges, and special rate provisions	2002 GRSP section
Conservation and Renewable Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed IP Rate	II.C.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible IP Rate Option	II.J.
Green Energy Premium	II.M.
Industrial Firm Power Targeted Adjustment Charge	II.O.
Rate Melding	II.Q.
Supplemental Contingency Reserves Adjustment	II.T.
Unauthorized Increase Charge	II.V.

Section IV. Transmission

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale.

NF–02

Nonfirm Power Rate

Section I. Availability

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of nonfirm energy under this schedule shall be determined by BPA.

This rate schedule supersedes the NF–96 schedule, which went into effect on October 1, 1996. Sales under the NF–02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

Section II. Rates, Billing Factors, and Adjustments

The average cost of nonfirm energy is 24.98 mills/kWh. The NF–02 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost.

A. Rates for Nonfirm Energy

1. Standard Rate

The Standard rate is any offered rate not to exceed 29.98 mills/kWh.

2. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

3. Incremental Rate

The Incremental Rate is the Incremental Cost of energy plus 2.00 mills/kWh, where the Incremental Cost is defined as all identifiable costs (expressed in mills/kWh) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

4. Contract Rate

The Contract Rate is 24.98 mills/kWh.

B. Billing Factor for Nonfirm Energy

The billing factor for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

C. Adjustments for Nonfirm Energy

All adjustments are described in the 2002 GRSPs. The applicable sections are identified for each adjustment.

Adjustments, charges, and special rate provisions	2002 GRSP section
Cost Contributions	II.E.
Unauthorized Increase Charge	II.V.

Section III. Determination of the Applicable NF Rate

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or any combination of these rates may be in effect.

A. Standard Rate

The Standard rate is available for all purchases of nonfirm energy.

B. Market Expansion Rate

1. Application of the Market Expansion Rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. Have a displaceable resource, displaceable purchase of electricity; or

b. Be an end-user load with a displaceable alternative fuel source. In addition, a purchaser must demonstrate one of the following:

a. Shutdown or reduction of the output of the displaceable resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

b. Reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. Shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. Decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion Rate

a. When only one Market Expansion rate is offered:

Purchasers satisfying the Market Expansion Rate Qualifying Criteria specified in Section III.B.2 above, who purchased nonfirm energy directly from BPA, are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh.

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.00 mills/kWh.

b. When more than one Market Expansion rate is offered:

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh. The rate applicable to a purchaser will be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.00 mills/kWh.

C. Incremental Rate

The Incremental rate applies to sales of energy:

1. That is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. That BPA may at its option not produce or purchase; and 3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) minus 2 mills.

D. Contract Rate

The Contract rate applies to contracts (except power sales contracts offered pursuant to Sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. For sale of nonfirm energy; or

2. For determining the value of energy.

E. Western Systems Power Pool Transactions (WSPP)

BPA may make available nonfirm energy for transactions under the WSPP agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and will be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may not exceed the maximum rate specified in the WSPP agreement. The rate for WSPP sales may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside the agreement.

F. End-User Rate

BPA may agree to a rate formula for nonfirm energy purchases by end-users. Such rate or rate formula will be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

Section IV. Delivery

A. Rate of Delivery

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. When BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. When BPA must reduce nonfirm energy deliveries in order to serve firm loads.

Section V. Transmission

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale.

BPA'S 2002 General Rate Schedule Provisions for Power Rates

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General Rate Schedule Provisions

Section I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions

A. Approval of Rates

These 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions (2002 GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). Bonneville Power Administration (BPA) has requested that FERC make these rates and 2002 GRSPs effective on October 1, 2001, for customers who are billed by BPA on a calendar month basis and on the first day of the first billing month following that date for all other customers. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These 2002 Wholesale Power Rate Schedules and the 2002 GRSPs associated with these schedules supersede BPA's 1996 rate schedules (which became effective October 1, 1996) to the extent stated in the Availability section of each rate schedule. These schedules and 2002 GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts as amended: The Bonneville Project Act, the Regional Preference Act (P.L. 88–552), the Federal Columbia River Transmission System (FCRTS) Act (P.L. 93–454), the Northwest Power Act (P.L. 96–501), and the Energy Policy Act of 1992 (P.L. 102–486).

These 2002 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Late Payment Provisions

Bills not paid in full on or before close of business on the due date shall be subject to an interest charge of one-twentieth percent (0.05 percent) applied each day to the unpaid amount. This interest charge shall be assessed on a daily basis until such time as the unpaid amount is paid in full.

Remittances will be accepted without assessment of the charges referred to in the preceding paragraph provided payment was received on or before the due date. The due date is the 20th day after the issue date of the bill unless the 20th day is a Saturday, Sunday, or Federal holiday, in which case the due date is the next business day. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date, and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the Purchaser. However, such cancellation shall not affect the Purchaser's liability for any previously accrued charges under such contract.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

Section II. Adjustments, Charges, and Special Rate Provisions

A. Conservation and Renewables Discount (C&R Discount)

1. Description of the Discount

To encourage and support the development of conservation projects and renewable resources in the Pacific Northwest, BPA is offering a Conservation and Renewables Discount (C&R Discount) to customers purchasing under the Priority Firm (PF–02), New Resources (NR–02), and Residential Load (RL–02) rate schedules. Customers purchasing under the Industrial Firm Power Rate (IP–02) will be eligible to the extent that the C&R Discount does not reduce their effective rate below the DSI floor rate. Regional public agency customers with Pre-Subscription contracts with collared pricing provisions may be eligible for the C&R Discount subject to contract provisions. The amount of the Discount will be a fixed monthly amount based on the customer's forecasted purchases from BPA under its Subscription contract. Following the end of the Discount Period (which is the end of the rate period or the customer's contract term, whichever comes first), BPA will evaluate the customer's investments in eligible conservation and renewable resource projects during the Discount Period. Any customer that has not spent at least as much money on eligible activities as the cumulative discount received from BPA must reimburse the difference to BPA.

2. Calculation and Application of the Discount

a. Overview of the Discount

The C&R Discount will be included as a fixed dollar credit in the monthly power bill of each participating customer. The credit will equal the customer's forecasted average monthly Subscription contract (in megawatts) multiplied by the unit discount. (Because the average contract is used, the discount does not vary by month).

b. Determination of the ''Unit Discount''

The unit discount will equal 0.5 mills per kilowatthour (kWh).

c. Determination of Individual Customer Discounts

For a participating customer buying power from BPA under a Subscription contract for the entire five-year rate period, BPA will determine the monthly dollar discount by multiplying the customer's forecasted average monthly power consumption over the rate period by the unit discount.

d. Annual Review of Individual Customer Discounts

At least 30 days prior to the start of each fiscal year, customers will submit adjustments to the section c monthly discounts based on changes to the customers load as specified in their BPA contract.

e. Application of the Discount

The C&R Discount will be applied after BPA has determined all other charges and credits on the participating customer's power bill.

BPA will provide the discount even in those months when the discount amount is larger than the customer's total power bill amount.

3. Qualifying Expenditures

Participating customers shall record all qualifying expenditures to ensure full credit for their conservation and renewable resource activities. Qualifying expenditures are those that meet technical standards developed by the Regional Technical Forum as approved by BPA.

Although BPA will provide the credit on a monthly basis, the customer has no obligation to adhere to any particular expenditure pattern. To retain the full discount provided by BPA, the participating customer must make qualifying expenditures during the Discount Period in an amount equal to, or exceeding, the cumulative C&R Discount received from BPA during the Discount Period.

4. Reporting

a. Interim Conservation and Renewable Reports

Participating customers shall submit to BPA annual Interim Conservation and Renewable Reports at the end of each fiscal year of the rate period (i.e., 10/01/01 to 9/30/02; 10/01/02, to 9/30/03; etc.). The Interim Report shall show the customer's cumulative discounts received to date and their cumulative qualifying expenditures. If the report shows that the customer's qualifying expenditures are less than or equal to its discount receipts by 5 percent or more, the customer must indicate in its report how it plans to adjust its expenditures to ensure that it will retain the full discount after the Discount Period.

b. Final Reconciliation Reports

At the end of the Discount Period the participating customer shall prepare a Final Reconciliation Report. This report shall be submitted and received by BPA one month after the end of the Discount Period (November 1, 2006, for participating customers' purchasing power from BPA for the full five-year rate period).

This report shall identify:

i. The cumulative C&R Discount that the customer has received from BPA during the Discount Period, and

ii. The total qualifying expenditures that the customer has made during the Discount Period segregated into the following four categories:

I. Incremental Conservation

II. Renewable Resources

III. Low Income Weatherization

IV. Support Activities (i.e., administrative, advertising, R&D, and evaluation

c. Certification of Incremental Spending

Each Interim Report and the Final Reconciliation Report shall include language certifying the participating customer's actual incremental spending, such as:

''[Customer] certifies that the expenditures documented in this report are incremental increases in this organization's budget for the current operating year beyond what we planned to spend absent the discount.''

d. Exemption Language for State and Municipal Initiatives

If States, municipalities, or other governmental bodies in the BPA service territory require, by law or regulation, that a utility, which is a participating customer in the C&R Discount, to acquire or invest in new conservation and/or a new renewable resource project, then such acquisitions and investments will be deemed as incremental budget increases for the purposes of section 4.c. above.

5. Reimbursement

a. Customers Whose Expenditures Exceed the Threshold

No reimbursements are required of any participating customer whose total expenditures over the Discount Period equal or exceed the total cumulative C&R Discount received from BPA.

b. Customers Whose Expenditures Fall Below the Threshold

If a participating customer's Final Reconciliation Report shows that the cumulative discount received from BPA exceeds the customer's total qualifying expenditures, the customer may take an additional month (for a total of two months after the end of the Discount Period) to make the necessary qualifying expenditures and prepare a Revised Final Reconciliation Report. The final report is due to BPA within two months of the end of the Discount Period (December 1, 2006, for the five-year customers). If the customer's qualifying expenditures still do not equal or exceed its cumulative discount, the customer must reimburse the difference to BPA. Such reimbursement shall be made within the same two-month grace period and shall be made using the same payment method as the customer uses for paying its wholesale bill.

BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2006, the five-year customers) shall be subject to a late payment charge as described in their Subscription contract.

6. Revenue Dividends

a. Implementation

If BPA declares that there is a dividend during this rate period, the first $15 million will be allocated to conservation and renewable resource development. BPA will distribute the C&R portion of any declared dividend in the same manner outlined in this section with the following modifications:

1. In order to receive their portion of the C&R dividend, customers must be actively participating in the basic C&R Discount effort; and

2. Participating customers must spend two dollars on eligible activities to receive one dollar of their dividend share (i.e., any C&R dividend will be leveraged on a 2 for 1 basis).

3. The unit discount for participating customers receiving the dividend will set at $0.75 per MWh during the months the dividend is in effect.

B. Conservation Surcharge (PF/NR Only)

The Conservation Surcharge, where implemented shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current conservation surcharge policy, and the customer's power sales contract with BPA. The PF and NR rate schedules are subject to the Conservation Surcharge.

C. Cost-Based Indexed IP Rate

The Cost-Based Indexed IP Rate option shall be offered at BPA's discretion to a DSI Purchaser who makes a contractual commitment to purchase power for all five years of the rate period from BPA that is subject to the IP Targeted Adjustment Charge (IPTAC). The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser. The following criteria will be used in establishing any flexible rate:

1. Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under this rate option must be equivalent to or greater than, on a net present value basis, the revenues BPA would have received had the IPTAC specified in the IP–02 rate schedule been applied to the same sales.

2. Risk Adjustments: Risk, both credit risk associated with individual customers and price risk associated with power and commodity prices, will be factors in establishing any flexible rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a ''margin deposit'' expense charge built into the rates, or other methods acceptable to BPA.

3. Industry Index: The Cost-Based Indexed IP Rate will be adjusted on a regular basis consistent with a negotiated cash or financial index. Adjusting the price of the Cost-Based Indexed IP Rate with the fluctuations in a world aluminum price index would be one use of an industry index.

4. Lower Rate Limit and Upper Rate Limit: A lower and upper rate limit will bound the Cost-Based Index and establish the minimum and maximum prices to be charged during the contract period.

D. Cost-Based Indexed PF Rate

The Cost-Based Indexed PF Rate will be offered to all firm load requirements customers who wish to convert their applicable PF rate under their contracts to a market-indexed or floating price adjusted for BPA's risk. The following are features of this rate:

1. BPA and the customer will choose during contract negotiations a mutually agreed reference point and sponsor for the index used. For example, the California-Oregon border (location) and the Dow Jones cash or the New York Mercantile Exchange futures (sponsor), or some other combination to arrive at an agreed upon index.

2. BPA will base the index pricing on a current market forecast of the market index referenced. The expected Net Present Value (NPV) revenue of the forecast index prices will be adjusted by a HLH and a LLH Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rates. The MIMA reflects BPA's PF equivalent expected revenues at the time the contract is signed, including an insurance premium to ensure revenue sufficiency.

3. Customers must select this rate for the term of their Subscription contract that the 2002–2006 rate period covers. Customers who choose a contract length of less than five years and wish to renew will be subject to rates established under a new rate case.

4. Billing will be based on the index's average of the last 15 days of closing or posted daily prices at the reference point. The MIMA will be calculated as follows:

Index = average of last 15 days of closing or posted daily prices at the reference point.
PF = monthly PF HLH or LLH energy rate
Cost of Insurance = The premium on a physical and financial instrument used to mitigate the risk.
MIMA = Index − PF+Cost of Insurance

E. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.12 mills/kWh.

2. The approximate cost contribution of different resource categories to each rate schedule is as shown in Table A:

TABLE A

Rate schedule	Resource cost contribution		
	Federal base system*	Exchange*	New resources*
PF	100	0	0
IP	52.86	43.66	3.48
NR	52.86	43.66	3.48

* In percent.

F. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to posted power rates for Subscription sales on a temporary basis if Actual Accumulated Net Revenues (AANR) in the generation function fall below a threshold level.

The CRAC applies to power customers under these firm power rate schedules: Priority Firm Power [Preference (PF excluding Slice), Exchange Program, and Exchange

Subscription], IP–02, including under the IPTAC and Cost-Based Index Rate, RL–02 including the financial portion of any Residential Exchange Settlement under this rate schedule, NR–02, and Subscription purchase under FPS. The CRAC does not apply to Pre-Subscription rates or Slice purchases.

1. Formula for the Calculation of the Revenue Amount and CRAC Percentage

If the AANR in any fiscal year 2001 through 2004 falls below the CRAC Threshold for that same fiscal year, the CRAC triggers, and rates will be increased for a 12-month period beginning the following April. The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
CRAC Threshold—AANR; or
The annual Maximum Planned Recovery Amount, shown in Table B below.

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.

Where CRAC Threshold is the ‘‘trigger point’’ for invoking a rate increase under the CRAC. The threshold is pre-specified for the end of fiscal years 2001, 2002, 2003, 2004, and 2005 in Table B.

Where AANR is generation function net revenues, as accumulated since 1998, at the end of each of the fiscal years 2001 through 2005. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. 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, will be included in determinations under the CRAC. Accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent auditing firm.

Where Maximum Planned Recovery Amount is the maximum amount planned to be recovered through the CRAC beginning in April following the end of a fiscal year in which the AANR falls below the CRAC Threshold.

If the AANR in fiscal year 2005 falls below the CRAC Threshold, the CRAC triggers, and rates will be increased for a six-month period beginning the following April. The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
(CRAC Threshold − AANR) divided by 2; or $87.5 million ($175 million divided by 2)

TABLE B

Fiscal year	CRAC threshold (AANR, $ millions)	Maximum planned recovery amount (beginning following April)
2001	−350	125
2002	−350	135
2003	−200	150
2004	−200	150
2005	−200	87.5

Once the Revenue Amount is determined, that amount will be converted to the CRAC Percentage. The CRAC Percentage is the percentage increase in each of the firm power rate schedules listed above. This percentage will be applied for a period of time to generate the additional (CRAC) revenue. The CRAC Percentage will be determined by the following formula:

CRAC Percentage =
Revenue Amount
Divided by
CRAC Revenue Basis,

Where CRAC Revenue Basis is the total generation revenue for the loads subject to CRAC, plus any Slice loads, for the fiscal year in which the CRAC implementation begins, based on the then most current revenue forecast.

Each non-Slice product's total charge for energy, demand and load variance will be increased by this CRAC Percentage amount.

2. CRAC Adjustment Timing

In January of each year of the rate period, the Administrator will determine whether the AANR at the end of the preceding fiscal year fell below the CRAC Threshold. If the AANR is below the CRAC Threshold, the Administrator will propose, in January, to increase applicable rates effective in the following April. The adjustment is applied to power deliveries beginning April 1. Any such increase beginning in fiscal years 2002–2005 remains in effect through March of the following year. An increase beginning in the final fiscal year of the rate period (2006) will remain in effect through September 2006.

3. CRAC 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 fiscal year ending September 30. By no later than December 1 of each year, BPA shall also post on its World Wide Web site the unaudited AANR.

b. Notice of CRAC Trigger

BPA shall notify all customers and rate case parties on or about January 15 in each of the fiscal years 2002–2006, if the AANR fell below the CRAC Threshold for that fiscal year and rates will be adjusted under the CRAC. (If the December unaudited AANR report for the generation function indicated that the CRAC Threshold might be reached, and the audited actuals show that it has not triggered, customers and rate case parties will be so notified.) Notification will include the audited AANR for the prior fiscal year, the calculation of the Revenue Amount, and the estimated CRAC Percentage. 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 CRAC implementation process.

On or about February 1 of any of the fiscal years 2002–2006 in which the AANR falls below the CRAC Threshold, BPA staff shall conduct a public forum to explain the AANR result, the calculation of the Revenue Amount and the CRAC Percentage, and demonstrate that the CRAC has been implemented in accordance with the GRSPs. The forum will provide an opportunity for public comment.

On or about March 1 of any of the fiscal years 2002–2006 in which the AANR falls below the CRAC Threshold, the BPA Administrator shall notify all customers to whom the CRAC applies of the final calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

G. Demand Adjuster

The Demand Adjuster is applied to a customer's demand billing factor. It is a number less than or equal to one calculated by dividing the customer's Total Retail Load on the Generation System Peak by the customer's Total Retail Load on their system peak. The minimum Demand Adjuster is 0.6 (six tenths). The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

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 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: Priority Firm Power [Preference (PF excluding Slice), Exchange Program, and Exchange Subscription], IP–02 including under the IPTAC and Cost-Based Index Rate, RL–02 including the financial portion of any Residential Exchange Settlement under this rate schedule, NR–02, and Subscription purchases under FPS. The DDC does not apply to Pre-Subscription rates or Slice purchases, unless those customers participate in the C&R Discount and a distribution is made to eligible participants of that program.

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

''Stakeholders'' are groups 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. A full identification of stakeholders will be provided for comment in the public consultation process.

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 fiscal years 2001–2005 are above the DDC Threshold value.

Actual Accumulated Net Revenues (AANR) are generation function net revenues, as accumulated since 1998, at the end of each of the fiscal years 2001 through 2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. 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 $500 million for the end of fiscal years 2001, 2002, 2003, 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 Treasury Payment Probability (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 fiscal year 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

On or about January 15 of each year of the rate period (FY 2002–2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold: (1) Customers and rate case parties will be so notified; and (2) 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 fiscal year 2002–2005, remain in affect 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 Conservation and Renewables Discount Program (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 Conservation and Renewables Discount GRSP, Section II.A.

BPA intends to conduct a separate public consultation process by October 1, 2001, 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 fiscal year ending September 30. By December 1 of each year, BPA shall post on its World Wide Web site the unaudited AANR.

b. Notice of DDC Trigger

On or about January 15 in each of the fiscal years 2002–2006, 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 fiscal year, 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 fiscal years 2002–2006 in which the AANR exceeds the DDC Threshold, the Administrator will post the Five-Year Forecast on BPA's World Wide Web site 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 fiscal years 2002–2006 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.

I. Excess Factoring Charges

1. Excess Within-Day Factoring Charge

The within-day factoring test compares the hour-by-hour shape of the customer's load to the customer's hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kilowatthours, than the underlying load would have used.

Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to that amount of hourly energy in excess of the authorized maximum energy amounts defined by the customer's within-day load shape.

The total amount of Excess Within-Day Factoring Charge during the HLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California ISO Supplemental Energy price (NP15) and the lowest hourly HLH California ISO Supplemental Energy price (NP15).

The total amount of Excess Within-Day Factoring Charge during the LLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH California ISO Supplemental Energy price (NP15) and the lowest hourly LLH California ISO Supplemental Energy price (NP15).

In the event that the index for ISO Supplemental Energy expires, that index will be replaced for the purpose of deriving Excess Within-Day Factoring Charges by another hourly energy index, such as the California PX (NW1 or NW 3), at a hub at which Northwest parties can trade.

2. Excess Within-Month Factoring Charges

The within-month factoring test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-to-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The within-day factoring test (see above) is not equipped to identify a factoring service issue if, for example, the customer resource deliveries were zero for a particular day. The within-month factoring test is equipped to address that type of instance. The within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess within-month factoring for each diurnal period is the greater of: (1) the sum of the amounts greater than the upper boundary; or (2) the sum of the amounts less than the lower boundary.

Excess Within-Month Factoring Charge applies to that amount of energy take that either exceeds or falls short of a range defined by: (1) a flat load placement on BPA; and (2) a load placement that follows the customer's actual load shape.

The Excess Within-Month Factoring quantities are reduced by any Unauthorized Increase Energy amounts in the like diurnal period, and only the residual is charged the Excess Within-Month Factoring Charge.

The Excess Within-Month Factoring during the HLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest peak DJ Mid-C Index price for firm power during the month LESS the lowest peak DJ Mid-C Firm Index price for firm power during the month.

c. The highest average HLH California ISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays) during the month LESS the lowest average HLH California ISO Supplemental Energy price (NP15) for the same period.

The Excess Within-Month Factoring during the LLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest offpeak DJ Mid-C Index price for firm power during the month LESS the lowest offpeak DJ Mid-C Index price for firm power;

c. The highest average LLH California ISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sunday) during the month LESS the lowest average LLH California ISO Supplemental Energy price (NP15) for the same month in the same time period.

In the event that the index for ISO Supplemental Energy or DJ Mid-C Index expires, that index will be replaced for the purpose of deriving Excess Within-

Month Factoring Charges by another hourly or diurnal energy index, such as the California PX (NW1 or NW3), at a hub at which Northwest parties can trade.

J. Flexible IP Rate Option

The Flexible IP rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option for all five years of the rate period. The charges and billing factors under this option will be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible IP rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the IP rate schedule Section II been applied to the same sales.

The Flexible IP rate contract may establish a limit on the amount of power purchased at the Flexible IP rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy charges specified in the IP rate schedule Section II unless such power would be charged as an Unauthorized Increase.

Risk Adjustments: Credit risk associated with individual customers will be a factor in establishing any flexible rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a ''margin deposit,'' expense charge, built into the rates, or other methods acceptable to BPA.

K. Flexible NR Rate Option

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the NR rate schedule Section II been applied to the same sales.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy (and Load Variance and SUMY, if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

The Flexible NR rate option is only available for development of an energy rate that is stepped up in FY 2005 and 2006.

L. Flexible PF Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the PF rate schedule Section II been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy (and Load Variance, and SUMY if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

The Flexible PF rate option is only available for development of an energy rate that is stepped up in FY 2005 and 2006.

M. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from zero to $40/megawatthour (MWh) that a customer elects to pay BPA to ensure that BPA is producing some system power from Environmentally Preferred Power (EPP) resources. The GEP is the difference between the customer's applicable average annual energy charge under the PF–02, RL–02, NR–02, and IP–02 rates and the total cost of the EPP resource selected by the customer. The GEP is applied to the number of EPP MWhs that the customer has elected to purchase. BPA guarantees the customer paying the premium that BPA will produce an amount of EPP equal to the amount of energy subject to this adjustment. The GEP will be charged in a line item on the monthly power bill of each participating.

The costs to be considered in determining the applicable GEP include, but are not limited to:

- Costs of existing EPP resources, over and above the cost of BPA system resources.
- Costs of new EPP resources, over and above the cost of BPA system resources.
- Costs of BPA system resources.
- Endorsement fees for specific EPP resources.
- Market purchases of EPP resources.
- Transmission and other services required to integrate EPP resources into the BPA system.

2. Calculation and Application of the Premium

a. Determination of the Premium

For a customer buying power from BPA under a requirements firm power sales contract, the amount of EPP and the premium will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation during the Subscription window. The charge will not exceed $40 per MWh and may be as low as zero. The premium will be zero if the unit cost of the GEP resource(s) dedicated to the customer is equal to, or less than, the energy charge of the applicable rate. The premium will be equal to the average unit cost of the GEP resource(s) minus the applicable average PF–02, RL–02, NR–02, and IP–02 energy charge.

b. Determination of Individual Customer GEP

(1) During the Subscription window, customers will be provided notice of the availability of specific GEP products and associated premiums. The total GEP

for the customer will be based on the customer's elections of product amounts and content.

(2) The average annual energy charge will be calculated as the average per kilowatthour (kWh) charge for an annual flat undelivered product using the energy charges applicable to the customer. Where customers are purchasing under more than one rate schedule, the average energy charge will be calculated using expected loads and applicable rate schedules.

(3) The individual customer GEP for billing will be the total cost of the product selected by the customer minus the average annual energy charge.

c. Application of the GEP

The GEP will be applied after BPA has determined all other charges and credits except the Conservation and Renewables Discount line item, on the participating customer's power bill.

d. Billing for the Premium

The customer's bill will include a line item showing the kWh amount of EPP purchased times the GEP for the products elected and the total cost. The calculation will appear as:

(EPP amount) kWh * GEP mills/kWh = $XXXXX

N. Guaranteed Delivery Charge (NF only)

A surcharge of 2.00 mills/kWh of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the NF Standard rate or Market Expansion rate.

O. Industrial Firm Power Targeted Adjustment Charge (IPTAC)

1. Availability

The Industrial Firm Power Targeted Adjustment Charge (IPTAC) pertains to the IP rate schedule. The IPTAC will be applied to Firm Power requirements service of DSIs who take service from a combination of Federal inventory and power purchased from the market during the 2002 rate period.

The maximum total requirements service the IPTAC will be developed for, and applied to, is 1,440 aMW (flat, annual block). The total inventory used to provide this requirement service will be composed of 990 aMW from Federal inventory and 450 aMW of market purchases.

There will be two rates for the IPTAC product. 1210 aMW will be sold at $23.50 per MWh, and 230 aMW sold at $25 per MWh.

P. Low Density Discount

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of Priority Firm Power, New Resources Firm Power and Residential Load Firm Power service: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase Charges, Excess Factoring Charges, transmission charges or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

a. The Kilowatthour/Investment Ratio

The kWh/Investment (K/I) ratio is calculated annually based on the data supplied by June 30 for the previous CY. The K/I ratio is calculated by dividing the Purchaser's Total Retail Load during the CY by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of the CY.

b. The Consumers/Mile of Line Ratio

The Consumers/Mile of Line (C/M) ratio is determined annually using the data supplied by June 30 for the previous CY. The C/M ratio is calculated by dividing the maximum number of consumers on the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as an additional billed consumer.

The number of pole miles of distribution line means the end of CY pole miles. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kilovolt or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

These calculations shall be based on CY data provided from the Purchaser's annual financial and operating reports. The Purchaser shall certify that the data submitted is correct and that no loads gained as provided in section 6, Retail Access Exclusion, are receiving LDD benefits.

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the Pacific Northwest (PNW). For Purchasers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the PNW and on the Purchaser's entire electric utility inside and outside the PNW. BPA will apply the eligibility criteria and discount percentages to the Purchaser's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Purchaser's eligibility for the LDD will be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Purchaser with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

A Purchaser who has not provided BPA with the requisite pieces of data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior CY, shall be declared ineligible for the LDD, effective the upcoming October 1.

If a Purchaser's data was submitted on time and a revision is necessary to the data, the revised data must be resubmitted no later than 12 months after the original submission date to be considered for an adjustment.

2. Eligibility Criteria

To qualify for a discount, the Purchaser must meet all five of the following eligibility criteria:

a. The Purchaser must serve as an electric utility offering power for resale;

b. The Purchaser must agree to pass the benefits of the discount through to the Purchaser's eligible consumers within the region served by BPA;

c. The Purchaser's average retail rate for the reporting year must exceed the Purchaser's average cost of BPA power purchases under the applicable rate for the qualifying period by at least 10 percent. For CY 2001, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable 1996 rate for the first nine months and under the applicable 2002 rate for the last three months. For CY 2002 and beyond, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable rate for all 12 months;

d. The Purchaser's K/I ratio must be less than 100; and

e. The Purchaser's C/M ratio must be less than 12.

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2001, in accordance with section 4 below. The discount will be the sum of the two potential discounts for which the Purchaser qualifies, based on the following Table C. The discount shall not exceed 7 percent.

TABLE C.—LDD PERCENTAGE DISCOUNT TABLE

Percentage discount	Applicable range for KWh/investment (K/I) ratio	Applicable range for consumers/mile (C/M) ratio
0.0	35.0 ≤ X	12.0 ≤ X
0.5	31.5 ≤ X < 35.0	10.8 ≤ X < 12.0
1.0	28.0 ≤ X < 31.5	9.6 ≤ X < 10.83
1.5	24.5 ≤ X < 28.0	8.4 ≤ X < 9.6
2.0	21.0 ≤ X < 24.5	7.2 ≤ X < 8.4
2.5	17.5 ≤ X < 21.0	6.0 ≤ X < 7.2
3.0	14.0 ≤ X < 17.5	4.8 ≤ X < 6.0
3.5	10.5 ≤ X < 14.0	3.6 ≤ X < 4.8
4.0	7.0 ≤ X < 10.5	2.4 ≤ X < 3.6
4.5	3.5 ≤ X < 7.0	1.2 ≤ X < 2.4
5.0	X ≤ 3.5	X < 1.2

4. LDD Phase-Out Adjustment

If the Purchaser satisfies the eligibility criteria (2. a. through e.), and the calculated discount differs from the existing discount by more than one-half of 1 percent, the applicable discount will be:

a. The existing discount plus ½ percent if the calculated discount exceeds the existing discount; or

b. The existing discount minus ½ percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each October 1 until the then-current calculated discount is fully phased out.

The Purchaser is not eligible to receive any discount, effective each October, if the Purchaser fails to meet the eligibility criteria in section 2. a. through e.

5. Benefits Legislation Exclusion

If the Federal government or a State, or local government adopt(s) a law, regulation or other provision that establishes benefits for low density and/or rural electric systems that are similar to benefits provided by BPA's LDD, then the Purchaser's service territory within that jurisdiction shall no longer be eligible to receive the LDD. The effective date for discontinuation of the LDD and the Phase-Out Adjustment shall be the implementation date of the jurisdiction's benefits provision legislation. BPA will evaluate new provisions and determine, in BPA's judgment, whether they provide benefits similar to the LDD. If BPA concludes that the benefits are similar, BPA will conduct a public comment process before issuing a final decision.

6. Retail Access Exclusion

Load that is gained by a Purchaser as a direct result of retail access rights established by Federal, State, or local legislation, and that would not otherwise have been gained absent such legislation, is not eligible to receive the benefits provided by the LDD. The Purchaser shall not pass the benefits of the LDD to its gained load consumers.

Q. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customer's rate choices and maintaining the distinction would increase BPA's overall cost of providing rate choices. For administrative simplicity upon mutual agreement between BPA and the customer, BPA may offer to meld the customer's rate choices into a single composite set of rates that reflects the specific choices made by the customer. BPA will ensure that this melded set of rates will result in a bill that is nearly mathematically equivalent to applying the customer's individual choices throughout the rate period. BPA will provide the affected customer the calculations it used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before it implements the melded rates. Melded rates established by BPA will continue until one of the customer's rate choices expires, or a rate adjustment occurs that is provided for under the chosen rate schedules (*e.g.,* Cost Recovery Adjustment Clause), or a significant change in the loads applicable to the rates occurs.

R. Slice True-Up Adjustment

By March 31 of each 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 rate case (except for the Inventory Solution which is billed based on the estimate from the 2002 rate case). This true-up will be the True-Up Adjustment Charge and will be applied to the customer's May bill. In addition, an interim true-up adjustment procedure to allow for an intermediate true-up prior to March 31, will be developed in the power sales contracts with the customers.

S. Stepped Up Multiyear Block (SUMY)

The SUMY Block charge applies to Block purchases if the annual amounts increase (i.e., step up) over multiple years of a purchase commitment term due to increases in customer net requirement which are not subject to a Targeted Adjustment Charge (TAC).

The cost for the SUMY Block service is the difference between PF–02 rates and the AURORA On-and Off-Peak market price forecast in the final rate proposal.

The starting basis for computing the SUMY Block quantities will be the purchaser's subscribed block amount for the period October 2001 through September 2002. Costs will be computed for 24 monthly blocks (12 HLH and 12 LLH) for each year of the rate period. Each year's monthly amount above the base year's monthly amount is the stepped up quantity. Total cost is the sum of each month's HLH and LLH stepped up quantities times each month's HLH and LLH costs.

The SUMY charge is the total cost of the SUMY Block service divided by the total Block energy purchase including stepped up amounts. The charge is in addition to the PF and NR energy and demand rates that the customer will pay for these power purchases.

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Table D

BASIS FOR SLICE TRUE-UP ADJUSTMENT CHARGE

Generation Expenses ($thousands)	2002		2003		2004	
Operating Expenses	**Total**	**Slice**	**Total**	**Slice**	**Total**	**Slice**
CSRS Pension Expense	27,600	27,600	17,550	17,550	15,450	15,450
Power Marketing	16,000	16,000	15,700	15,700	8,800	8,800
Wheeling (GTAs)	52,000	50,000	52,000	50,000	52,000	50,000
Power Scheduling	20,900	20,900	12,800	12,800	12,100	12,100
ST Purchased Power/Upstr Benefits	154,900	1,990	151,402	2,050	160,205	2,111
PNCA Interchange	-	-	-	-	-	-
Generation Oversight	2,964	2,964	2,950	2,950	3,050	3,050
Conservation & Consumer Services (incl EE)	29,351	29,351	27,763	27,763	28,063	28,063
Fish & Wildlife	131,700	131,700	138,000	138,000	140,100	140,100
Administrative & Support Services	17,350	17,350	16,650	16,650	16,650	16,650
Planning Council	5,100	5,100	5,100	5,100	5,100	5,100
Corps of Engineers O&M	108,000	108,000	112,000	112,000	112,000	112,000
U.S. Fish & Wildlife O&M	15,400	15,400	16,197	16,197	16,995	16,995
Bureau of Reclamation O&M	47,000	47,000	48,300	48,300	48,300	48,300
Colville Settlement	16,000	16,000	16,000	16,000	16,000	16,000
Renewable Projects	20,302	20,302	20,117	20,117	19,968	19,968
WNP-1 O&M	400	400	384	384	384	384
WNP-2 O&M/Capital Requirements	154,094	154,094	163,824	163,824	170,724	170,724
WNP-3 O&M	3,086	3,086	3,169	3,169	3,169	3,169
Trojan Decommissioning	9,600	9,600	4,200	4,200	2,600	2,600
Between Business Line Expense [1]	151,941	41,662	157,689	45,309	165,524	54,947
LT Power Purchases	26,805	26,805	27,245	27,245	27,682	27,682
Rate Pledge Adjustment						

[1] Includes BPA Generation-Integration (under Ancillary Services), PF Transmission pass-through, PNCA and NTS Transmission, CEA Transmission, and Between Business Line Expenses.

	2005		2006		Rev Req
Operating Expenses	**Total**	**Slice**	**Total**	**Slice**	
CSRS Pension Expense	13,250	13,250	11,600	11,600	85,450
Power Marketing	6,800	6,800	5,000	5,000	52,300
Wheeling (GTAs)	52,000	50,000	52,000	50,000	250,000
Power Scheduling	12,800	12,800	12,700	12,700	71,300
ST Purchased Power/Upstr Benefits	169,125	2,174	176,294	2,240	10,565
PNCA Interchange	-	-	-	-	-
Generation Oversight	3,050	3,050	3,150	3,150	15,163
Conservation & Consumer Services (incl EE)	28,463	28,463	28,763	28,763	142,401
Fish & Wildlife	142,900	142,900	144,400	144,400	697,100
Administrative & Support Services	16,650	16,650	16,650	16,650	83,950
Planning Council	5,100	5,100	5,100	5,100	25,500
Corps of Engineers O&M	112,000	112,000	112,000	112,000	556,000
U.S. Fish & Wildlife O&M	17,892	17,892	18,789	18,789	85,273
Bureau of Reclamation O&M	48,300	48,300	48,300	48,300	240,200
Colville Settlement	16,000	16,000	16,000	16,000	80,000
Renewable Projects	19,885	19,885	19,836	19,836	100,109
WNP-1 O&M	384	384	384	384	1,936
WNP-2 O&M/Capital Requirements	173,824	173,824	179,824	179,824	842,290
WNP-3 O&M	3,169	3,169	3,169	3,169	15,762
Trojan Decommissioning	2,600	2,600	2,600	2,600	21,600
Between Business Line Expense [1]	163,763	55,003	164,130	55,061	251,982
LT Power Purchases	28,279	28,279	28,763	28,763	138,774
Rate Pledge Adjustment					

[1] Includes BPA Generation-Integration (under Ancillary Services), PF Transmission pass-through, PNCA and NTS Transmission, CEA Transmission, and Between Business Line Expenses.

	2002		2003		2004	
Operating Expenses	**Total**	**Slice**	**Total**	**Slice**	**Total**	**Slice**
System Operation & Maintenance	**1,010,492**	**745,303**	**1,009,040**	**745,308**	**1,024,864**	**754,193**
WNP-1	177,704	177,704	167,856	167,856	174,623	174,623
WNP-2	197,442	197,442	244,980	244,980	233,624	233,624
WNP-3	153,720	153,720	152,993	152,993	149,232	149,232
Trojan	9,947	9,947	9,954	9,954	9,964	9,964
Conservation Financing	5,578	5,578	5,577	5,577	5,577	5,577
Renewable Projects	2,880	2,880	2,880	2,880	2,880	2,880
LT Power Purchases	15,917	15,917	15,916	15,916	15,920	15,920
Total Non-Fed. Projects Debt Service	**563,187**	**563,187**	**600,156**	**600,156**	**591,820**	**591,820**
Depreciation	95,288	95,288	97,910	97,910	100,170	100,170
Amort.: Conservation & Fish & Wildlife	80,002	80,002	78,321	78,321	71,755	71,755
Total Federal Projects Depreciation	**175,290**	**175,290**	**176,231**	**176,231**	**171,925**	**171,925**
IOU Payment (in lieu of Residential Exchange)	-		-		-	
Total Operating Expenses	**1,760,119**	**1,483,780**	**1,785,427**	**1,521,695**	**1,788,609**	**1,517,938**
Net Federal Interest Expense	**214,665**	**214,665**	**213,507**	**213,507**	**219,193**	**219,193**
Total Operating & Net Interest Expenses	**1,974,784**	**1,698,445**	**1,998,934**	**1,735,202**	**2,007,802**	**1,737,131**
Miscellaneous Expense [2]						
TOTAL ACCRUED EXPENSES FOR SLICE TRUE-UP		**1,698,445**		**1,735,202**		**1,737,131**

Revenue Credits	2002		2003		2004	
	Total	**Slice**	**Total**	**Slice**	**Total**	**Slice**
Ancillary and Reserve Service Revs.		87,336		87,233		88,072
PBL PF Trans. Pass-Through Revs.		14,190		14,247		14,304
Canadian Entitlement Credit		1,000		1,000		1,000
COE & USBR Project Revenues		8,100		8,100		8,100
4(h)(10)(c)		86,523		90,187		88,258
Colville Credit		4,600		4,600		4,600
FCCF		43,559		27,132		20,387
Sup/Ent Cap; Irr. Pump		938		707		471
Energy Efficiency Revenues		13,046		13,345		13,345
Property Trnfrs & Misc.		3,416		3,416		3,416
Miscellaneous Credits [3]						
Total Revenue Credits		**262,708**		**249,967**		**241,953**

[2] Includes Slice administrative expenses, WNP-2 economic displacement charges, conservation & renewables surcharge expenses, etc. The amounts associated with these expenses will not be determined until they actually are incurred. In some years, the amount for any of these expenses could be zero. In addition, Slice Administrative expenses are shared equally amongst Slice.

[3] Includes potential applicable revenue credits, the type and amount of which will be determined as they are accrued.

	2005		2006		Rev Req
Operating Expenses	**Total**	**Slice**	**Total**	**Slice**	
System Operation & Maintenance	**1,036,234**	**758,523**	**1,049,452**	**764,329**	**3,767,655**
WNP-1	167,910	167,910	179,992	179,992	868,085
WNP-2	187,825	187,825	211,976	211,976	1,075,847
WNP-3	149,480	149,480	147,836	147,836	753,261
Trojan	9,989	9,989	10,009	10,009	49,863
Conservation Financing	5,577	5,577	5,577	5,577	27,886
Renewable Projects	2,880	2,880	2,880	2,880	14,399
LT Power Purchases	15,933	15,933	15,935	15,935	79,621
Total Non-Fed. Projects Debt Service	**539,594**	**539,594**	**574,205**	**574,205**	**2,868,962**
Depreciation	102,215	102,215	104,164	104,164	499,747
Amort.: Conservation & Fish & Wildlife	69,466	69,466	64,950	64,950	364,494
Total Federal Projects Depreciation	**171,681**	**171,681**	**169,114**	**169,114**	**864,241**
IOU Payment (in lieu of Residential Exchange)	-		-		-
Total Operating Expenses	**1,747,509**	**1,469,798**	**1,792,770**	**1,507,647**	**7,500,858**
Net Federal Interest Expense	**224,550**	**224,550**	**221,653**	**221,653**	**1,093,568**
Total Operating & Net Interest Expenses	**1,972,059**	**1,694,348**	**2,014,423**	**1,729,300**	**8,594,426**
Miscellaneous Expense [2]					
TOTAL ACCRUED EXPENSES FOR SLICE TRUE-UP		**1,694,348**		**1,729,300**	**8,594,426**

Revenue Credits	2005		2006		Rev Req
	Total	**Slice**	**Total**	**Slice**	
Ancillary and Reserve Service Revs.		88,023		87,945	438,609
PBL PF Trans. Pass-Through Revs.		14,361		14,418	71,520
Canadian Entitlement Credit		1,000		1,000	5,000
COE & USBR Project Revenues		8,100		8,100	40,500
4(h)(10)(c)		89,687		92,149	446,804
Colville Credit		4,600		4,600	23,000
FCCF		10,600		6,492	108,170
Sup/Ent Cap; Irr. Pump		471		471	3,059
Energy Efficiency Revenues		13,345		13,345	66,426
Property Trnfrs & Misc.		3,416		3,416	17,080
Miscellaneous Credits [3]					
Total Revenue Credits		**233,603**		**231,936**	**1,220,168**

[2] Includes Slice administrative expenses, WNP-2 economic displacement charges, conservation & renewables surcharge expenses, etc. The amounts associated with these expenses will not be determined until they actually are incurred. In some years, the amount for any of these expenses could be zero. In addition, Slice Administrative expenses are shared equally amongst Slice.

[3] Includes potential applicable revenue credits, the type and amount of which will be determined as they are accrued.

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Formula for Calculating a Charge for SUMY Block Service

Step 1: Determine HLH MWh of SUMY Block. October 2002 HLH Block minus October 2001 HLH Block = HLH MWh of SUMY Block for October 2002

Step 2: Determine LLH MWh of SUMY Block. October 2002 LLH Block minus October 2001 LLH Block = LLH MWh of SUMY Block for October 2002

Step 3: Determine Cost of HLH SUMY Block service. HLH MWh of SUMY Block * (Aurora October 2002 On-Peak Market Price minus October 2002 PF HLH energy and demand rate) = Total Cost of October 2002 HLH SUMY Block service.

Step 4: Determine Cost of LLH SUMY Block service. LLH MWh of SUMY Block * (Aurora October 2002 Off-Peak Market Price minus October 2002 PF LLH energy rate) = Total Cost of October 2002 LLH SUMY Block service.

Step 5: Determine Cost for all months of the rate period by repeating Steps 1–4 for each month of the remaining purchase period always calculating the MWh difference from the first year and corresponding month. Calculate the price difference using that year's and month's market price and PF rate.

Step 6: Custom Charge: Divide the Net Present Value (NPV) of the stream of costs derived from Steps 1–5 by the NPV of the total block purchase including SUMY Block in MWh for the five-year period. The NPV uses a 6.8 percent discount rate and is present valued to October 2001.

Step 7: Billing Determinant: Custom charge is applied to each MWh of block purchase including the SUMY Block amounts.

T. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP–02 rate schedule will be adjusted to reflect the negotiated SCRA adjustment. PBL will negotiate with any DSI interested in providing Supplemental Contingency Reserves (Supplemental Reserves). Supplemental Reserves refers to generating capacity, and associated energy, fully available within 10 minutes notice of a system disturbance. PBL has established a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of reserves provided. The maximum amount PBL may pay for Supplemental Reserves from a DSI is capped at $5.92/kW-mo.

The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. Any Supplemental Reserves purchased by PBL must be consistent with NERC, WSCC, and NWPP criteria:

1. The interruptible load must be offline within five minutes after a call by BPA;
2. In the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties;
3. The interruptible load must be available to be offline for up to 60 minutes.

In addition to these required characteristics, the issues identified below will help define when PBL may pay the maximum value for Supplemental Reserves:

1. The extent to which PBL has the discretion when and how to use all operating reserves and to determine what resources to call on in the event of a system disturbance;
2. Whether there are limitations on the number of times or total minutes the reserves may be utilized.

U. Targeted Adjustment Charge

1. Availability

The Targeted Adjustment Charge (TAC) pertains to the PF rate schedule, except for PF exchange program and PF exchange Subscription rates. The TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. The TAC will be applied to the applicable rate for requirements service requested after the Subscription window closes.

TAC will also apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load(s) that had been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply PF–02. The TAC will apply if the annexed requirements service has been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

Where a public agency customer annexes residential and small farm load previously served by an IOU and such load was receiving BPA power or financial benefits through Subscription, the public agency customer will receive through assignment the right to the IOUs power and/or financial benefits applicable to the annexed load. BPA will deliver the same amount of firm power that was assigned by the IOU to the annexing public agency customer at the PF–02 rate. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the power assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the Customer's contract or until 2006, whichever occurs first. For five-year contracts that guarantee rates for a multitude of periods (for example, contracts that have both three-year and five-year components) the TAC applies until the end of the five-year rate period. If a new public requests service, the TAC, if any, must apply until 2006.

If a PF Preference customer is serving a portion of its load with a certifiable renewable resource eligible for the C&R Discount, or contract purchases of certified renewable resource power eligible for the C&R Discount for a period less than the term of the customer's BPA requirements firm power contract, then the customer may request, during the 2002 to 2006 rate period, requirements firm power service for such load at the end of the specified contract period at PF Preference (PF–02) without being subject to the TAC. This limited exception applies to the first 200 aMW in any contract year, or to amounts that BPA specifies in accordance with its Policy on the Determination of Net Requirements.

2. Energy Charge

The TAC is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedule, and is applied to that portion of the Purchaser's load that is subject to the TAC. The TAC rate adjustment will be established based on the following formula:

TAC = [(Incr $ * Incr Amt)—(Rate $ * Incr Amt)]/TAC Amt

Where:

TAC Amt = The amount of load subject to the TAC, determined monthly.

Rate $ = The monthly PF energy rate shown in the applicable rate schedule.

Inventory Amt=Amount of energy in inventory available to serve this load based on average annual Federal system firm resource capability, estimated using critical water excluding balancing purchases and purchases for system augmentation, from the 2002 rate case with updates if BPA determines that is necessary.

Incr $=Monthly cost to BPA, including a handling fee, of incremental power purchases expressed in mills/kWh. These costs also may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the California PX.

Incr Amt=Amount of incremental power required, determined monthly and defined as the TAC Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TAC Amt).

Incr $ is greater than Rate $ (If Incr $ is less than Rate $, the TAC is 0 mills/kWh).

TAC is the monthly rate adjustment in mills/kWh. BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific customer request. BPA will establish the cost of the additional power by the following methods:

- BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market.

V. Unauthorized Increase Charge

1. Charge for Unauthorized Increase in Demand

The amount of Measured Demand during a billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at the greater of:

a. Three (3) times the applicable monthly demand charge;

b. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or

c. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 (NOB).

In the event that the hourly California ISO Spinning Reserve Capacity market expires, the Unauthorized Increase Charge for demand shall be the greater of:

a. Three (3) times the applicable monthly demand charge;

b. The sum of hourly or diurnal prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

2. Charge for Unauthorized Increase in Energy

The amount of Measured Energy during a diurnal period of a billing month, day, or hour that exceeds the amount of energy the purchaser is contractually entitled to take during that period shall be billed the greater of:

a. One hundred (100) mills/kWh; or

b. For the month in question, the greater of:

(1) the highest diurnal DJ Mid-C Index price for firm power; or

(2) the highest hourly ISO California Supplemental Energy price (NP15).

In the event that either the ISO California Supplemental Energy price index or the DJ Mid-C Index expires, the index will be replaced for purposes of the Unauthorized Increase Charge for energy by:

(1) The highest price experienced for the month at the California PX, NW1 (COB);

(2) The highest price experienced for the month at the California PX, NW3 (NOB); or

(3) The highest price experienced for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

Section III. Definitions

A. Power Products and Services Offered By the Power Business Line of BPA

1. Actual Partial Service Product—Simple/Complex

The Actual Partial Service Products are core Subscription products that are available to purchasers who have a right to purchase from BPA for their requirements. These products are intended for customers who have contractual or generating resources with firm capabilities and therefore require a product other than Full Service. The Simple and Complex versions of this product category differ in that the Complex version is subject to the Factoring Benchmark tests in the billing process and to potential Excess Factoring Charges. The Simple version encompasses several possible approaches to customer resource declaration, all of which obviate the need for the Factoring Benchmark tests.

2. Block Product

The Block Product is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available in HLH and LLH quantities per month, with the hourly amount flat for all hours in such periods.

3. Block Product with Factoring

The Block Product with Factoring is a combination of the Block Product with the core Subscription staple-on product for Factoring Service. Factoring provides the service of distributing Block energy to follow Purchaser hourly load needs to the extent of such Block energy.

4. Block Product With Shaping Capacity

The Block Product with Shaping Capacity is a combination of the Block HLH energy product and the core Subscription staple-on product for Shaping capacity. Shaping capacity allows the customer to preschedule Block energy with some limited shape among HLHs within a contractually specified bandwidth.

5. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power (PF–02), New Resources Firm Power (NR–02), and Firm Power Products and Services (FPS–96), rate schedules. Such power is not available for the PF Exchange Program rate, the PF Exchange Subscription rate, and the Residential Load rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

a. Power sold for construction is to be used in the construction of the project.

b. Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.

c. Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Purchaser may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

d. Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

6. Core Subscription Products

BPA's Core Subscription Products are described in the BPA Product Catalog. Core Subscription Products are available at the posted rates for customers who have a right to purchase them.

The core products are:

- Actual Partial Service Product—Simple/Complex
- Block Product
- Block Product with Factoring
- Block Product with Shaping Capacity

- Full Service Product

7. Customer System Peak (CSP)

Customer System Peak (CSP) is the largest measured HLH Total Retail Load (TRL) amount in kilowatts for the billing period.

8. Full Service Product

Full Service is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources.

9. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

10. Load Variance

For core Subscription products, Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Through the Load Variance charge under the Full and Actual Partial Service Products, the customer's billing factors will follow actual consumption. Load Variance is not applicable to Block Product purchases. For purposes of pricing and rate tests under Pre-Subscription contracts, the Load Variance charge is deemed to correspond to the PF–96 Load Shaping charge.

11. New Resource Firm Power

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

a. For any New Large Single Load (NLSL); and

b. For Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

New Resource Firm Power is to be used to meet the Purchaser's firm power load within the PNW. Deliveries of New Resource Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

New Resource Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events. New Resource Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and the NWPP.

12. Nonfirm Energy

Nonfirm Energy is energy that is supplied or made available by BPA to a Purchaser under an arrangement that does not have the guaranteed continuous availability feature of Firm Power. Nonfirm energy is sold primarily under the Nonfirm Energy rate schedule, NF–02. Nonfirm energy also may be supplied under the NF–02 rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements. Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the Purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

13. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Exchange contracts with BPA. Priority Firm Power is not available to serve NLSLs. Deliveries of Priority Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

Priority Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events. Priority Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to AGC control signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the Residential Exchange Program. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities. The amount of power purchased and sold is equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm customers.

16. Slice Product

The Slice product is a power sale based upon an eligible customer's annual net firm requirements load and is shaped to BPA's generation from the Federal system resources over the year. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchaser's percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power.

B. Definition of Rate Schedule Terms

1. 2002 Contract

A 2002 contract is a contract for service in the FY 2002 through 2006 rate period that is signed after January 1, 1999.

2. Annual Billing Cycle

The Annual Billing Cycle is the 12 months beginning with the customer's first monthly power bill for deliveries in the first billing month starting on or after October 1.

3. Billing Demand

The Purchaser's Billing Demand is the amount of capacity to which the demand charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand quantity for each product. The calculation of Billing Demand is described in the customer's contract.

4. Billing Energy

The Purchaser's Billing Energy is the amount of energy to which the energy charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Energy quantity for each product. Billing Energy is divided into HLH and LLH for this rate period.

5. California Independent System Operator (California ISO)

The FERC regulated control area operator of the ISO transmission grid. Its responsibilities include providing non-discriminatory access to the transmission grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The ISO has no affiliation with any market participant.

6. California ISO Spinning Reserve Capacity

The portion of unloaded synchronized generating capacity, controlled by the California ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

7. California ISO Supplemental Energy

Energy from generating units and other resources which have uncommitted capacity following finalization of the hour-ahead schedules and for which scheduling coordinators have submitted bids to the California ISO at least 30 minutes before the commencement of the settlement period.

8. California Power Exchange (California PX)

An independent agency responsible for conducting an auction for the generators seeking to sell energy and for loads which are not otherwise being served by bilateral contracts. The California PX is responsible for scheduling generation in its scheduling (e.g., day-ahead) markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and Utility Distribution Company's (UDC) using its market.

9. Contract Demand

The Contract Demand is the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

10. Contract Energy

Contract Energy is the maximum number of kilowatthours that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

11. Control Area

A Control Area is the electrical (not necessarily geographical) area within which a controlling utility operating under all NERC standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and power flow across interchange boundaries to other Control Areas.

12. Decremental Cost

Unless otherwise specified in a contractual arrangement, Decremental Cost as applied to Nonfirm Energy transactions is defined as:

a. All identifiable costs (expressed in mills/kWh) associated with the use of a displaceable thermal resource or end-use load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

b. All identifiable costs (expressed in mills/kWh) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the Purchaser.

13. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

14. Demand Entitlement

For purchases made under contracts for core Subscription products, Demand Entitlement is the largest HLH amount of power in kilowatts that the purchaser is entitled to receive from BPA during the billing period as specified in the contract.

15. Discount Period

The end of the rate period or the customer's contract term, whichever comes first.

16. Dow Jones Mid-C Indexes (DJ Mid-C Indexes)

Peak and offpeak price indexes for sale of firm and nonfirm power traded at the Mid-Columbia Bus.

17. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatthours).

18. Energy Entitlement

For purchases made under contracts for core Subscription products, HLH and LLH Energy Entitlement is the sum in kilowatthours of amounts for HLH and LLH energy respectively, that the purchaser is entitled to receive from BPA as specified in the contract.

19. Federal System

The Federal System is the generating facilities of the FCRPS, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. From which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. ''BPA's loads'' do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

b. Which BPA may use under contract or license; or

c. To the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

20. Firm Power (PF–02, IP–02, NR–02, RL–02)

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to Section 5 of the Northwest Power Act.

21. Full Service Customer

A Full Service customer is one who is purchasing power from BPA through the Full Service Product.

22. Generation System Peak

The Generation System Peak is the hour of the largest HLH output of the Federal System that occurs during the customer's billing period.

23. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. to the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

24. Inventory Solution Costs

Costs associated with BPA's potential actions to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process. It is currently not known whether an Inventory Solution will be necessary, or what form the Inventory Solution will take.

25. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the offpeak period hour ending 11 p.m. to the hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

26. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand provided by BPA to the Purchaser. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered ''unauthorized.'' Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined pursuant to the Purchaser's agreement with BPA, BPA shall adjust any abnormal Integrated Demand due to, or resulting from:

a. Emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

b. Emergencies on the Purchaser's facilities to the extent BPA determines that such facilities have been adequately maintained and prudently operated. BPA will follow its billing process in establishing the Billing Demand should an outage cause an unusual Billing Demand quantity. BPA will not give outage credits for demand.

27. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is provided by BPA to the Purchaser during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered ''unauthorized.'' Unauthorized increases are billed in accordance with the provisions of these GRSPs.

28. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered to a purchaser:

a. At each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand;

b. During each time period specified in the applicable rate schedule; and

c. During any billing period.

Such largest Integrated Demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Purchaser.

29. Metered Energy

The Metered Energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Purchaser:

a. At all points of delivery for which metered energy is the basis for determination of the Measured Energy; and

b. during any billing period.

30. Mid-Columbia Bus (Mid-C Bus)

The switchyards associated with five non-Federal hydroelectric projects, including Rocky Reach, Priest Rapids, Wanapum, Douglas, and McKenzie. The following Federal switchyards which are operated by BPA and interconnected with the non-Federal switchyards are also included: Valhalla, Columbia, Midway, Sickler, and Vantage.

31. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

32. NP15

The portion of the California ISO's control area north of transmission path 15.

33. NW1 (California-Oregon Border)

California PX and California ISO designation for delivery at COB (Captain Jack/Malin).

34. NW3 (Nevada-Oregon Border)

California PX and California ISO designation for delivery at NOB.

35. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

36. Point of Delivery (POD)

A Point of Delivery is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it could be located at the change of ownership point on a transmission line.

37. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically a point of integration is located at a resource site, but it could be located at some other interconnection point to receive system power from the customer.

38. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

39. Points of Metering (POM)

The Points of Metering (POM) shall be those points specified in the contract at which TRL and Metered Amounts are measured.

40. Pre-Subscription Contract

A contract for service in the FY 2002 through 2006 rate period that was signed prior to January 1, 1999, is a Pre-Subscription Contract.

41. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a Purchaser contracts to pay BPA for providing a product or service.

42. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

43. Retail Access

Retail Access is nondiscriminatory retail distribution access mandated either by Federal or State law which grants retail electric power consumers the right to choose their electricity supplier.

44. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kilowatts is the largest of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. To each system for which Scheduled Demand is the basis for determination of the Measured Demand;

b. During each time period specified in the applicable rate schedule; and

c. During any billing period.

Scheduled Demand is deemed delivered for the purpose of determining Billing Demand.

45. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. For each system for which Scheduled Energy is the basis for determination of the Measured Energy; and

b. During any billing period.

Scheduled Energy is deemed delivered for the purpose of determining Billing Energy.

46. Slice Administrative Costs

All overhead costs incurred by BPA that are attributable to the implementation of the Slice product.

47. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of all the line items in BPA's PBL revenue requirement as identified in all of the PBL's rate cases that are effective during the term of the Slice Purchaser's contract except for the following items: (1) transmission costs (other than those associated with the fulfillment of System Obligations); (2) power purchase costs (with the exception of those net costs incurred as part of the "Inventory Solution"); and (3) planned net revenues for risk.

See Table E for Slice Product Costing Table.

48. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy power sales beginning FY 2002.

49. Subscription Contract

See 2002 Contract.

50. System Obligations

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Table E

SLICE PRODUCT COSTING TABLE

PBL Costs ($000)	2002	2003	2004	2005	2006	TOTAL
GENERATION COSTS						
Federal Base System						
Hydro	$ 447,800	$ 455,373	$ 468,464	$ 479,149	$ 483,041	$ 2,333,825
Fish and Wildlife	$ 159,425	$ 167,905	$ 172,350	$ 176,722	$ 179,102	$ 855,504
Trojan	$ 19,547	$ 14,154	$ 12,564	$ 12,589	$ 12,609	$ 71,463
WNP #1	$ 178,104	$ 168,240	$ 175,007	$ 168,294	$ 180,376	$ 870,021
WNP #2	$ 351,536	$ 408,804	$ 404,348	$ 361,649	$ 391,800	$ 1,918,137
WNP #3	$ 153,720	$ 152,993	$ 149,232	$ 149,480	$ 147,836	$ 753,261
Total	**$ 1,310,131**	**$ 1,367,469**	**$ 1,381,965**	**$ 1,347,883**	**$ 1,394,764**	**$ 6,802,211**
New Resources						
Idaho Falls	$ 3,740	$ 3,737	$ 3,744	$ 3,754	$ 3,754	$ 18,729
Cowlitz	$ 14,914	$ 14,987	$ 15,051	$ 15,123	$ 15,196	$ 75,271
Firm Purchased Power	$ 17,723	$ 17,953	$ 18,187	$ 18,435	$ 18,681	$ 90,978
Other Acquisitions						
Total	**$ 36,377**	**$ 36,677**	**$ 36,982**	**$ 37,312**	**$ 37,631**	**$ 184,978**
Legacy Conservation	$ 131,799	$ 126,452	$ 114,284	$ 109,498	$ 101,240	$ 583,272
Energy Services Business	$ 11,349	$ 11,353	$ 11,321	$ 11,261	$ 11,227	$ 56,511
Other Generation Costs						
BPA Programs	$ 118,043	$ 98,774	$ 88,465	$ 84,222	$ 80,209	$ 469,713
Other						
WNP #3 Plant	$ 3,086	$ 3,169	$ 3,169	$ 3,169	$ 3,169	$ 15,762
Total	**$ 121,129**	**$ 101,943**	**$ 91,634**	**$ 87,391**	**$ 83,378**	**$ 485,475**
COSA Table Subtotal	**$ 1,610,784**	**$ 1,643,893**	**$ 1,636,185**	**$ 1,593,345**	**$ 1,628,240**	**$ 8,112,447**
CEA Transmission Costs	$ 13,514	$ 17,105	$ 26,685	$ 26,685	$ 26,685	$ 110,675
Ancillary and Reserve Service Costs	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 40,000
PBL PF Trans. Pass-Through Costs	$ 14,190	$ 14,247	$ 14,304	$ 14,361	$ 14,418	$ 71,520
PNCA & NTS Transmission Costs	$ 1,957	$ 1,957	$ 1,957	$ 1,957	$ 1,957	$ 9,785
General Transfer Agreement Costs	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 250,000
REVENUE REQUIREMENT CHECK	**$ 1,698,445**	**$ 1,735,202**	**$ 1,737,131**	**$ 1,694,348**	**$ 1,729,300 0**	**$ 8,594,426**
PF Conservation and Renewables Credit Costs						$ 96,416
IP Conservation and Renewables Credit Costs						$ 21,693
RL Conservation and Renewables Credit Costs						$ 21,900
LDD	$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 70,000
S & I Rate Mitigation Costs	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 20,000
Non-COSA Table Subtotal						$ 230,009
Total PBL Revenue Requirement						$ 8,824,435

Revenue Credits ($000)	2002	2003	2004	2005	2006	TOTAL
Ancillary and Reserve Service Revs.	$ 87,336	$ 87,233	$ 88,072	$ 88,023	$ 87,945	$ 438,610
PBL PF Trans. Pass-Through Revs.	$ 14,190	$ 14,247	$ 14,304	$ 14,361	$ 14,418	$ 71,520
Canadian Entitlement Credit	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
COE & USBR Project Revenues	$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 40,500
4(h)(10)(c)	$ 86,523	$ 90,187	$ 88,258	$ 89,687	$ 92,149	$ 446,804
Colville Credit	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 23,000
FCCF	$ 43,559	$ 27,132	$ 20,387	$ 10,600	$ 6,492	$ 108,170
Sup/Ent Cap; Irr. Pump	$ 938	$ 707	$ 471	$ 471	$ 471	$ 3,059
Energy Efficiency Revenues	$ 13,046	$ 13,345	$ 13,345	$ 13,345	$ 13,345	$ 66,426
Property Trnfrs & Misc.	$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 17,080
Total Revenue Credits						**$ 1,220,169**
Power Revenues Needed						**$ 7,604,267**

	2002	2003	2004	2005	2006	TOTAL
Firm System Augmentation (1112 aMWs on average	$ 252,064	$ 290,218	$ 253,541	$ 292,433	$ 279,879	$ 1,368,135
DSI Augmentation (450 aMWs)	$ 110,770	$ 110,770	$ 110,770	$ 110,770	$ 110,770	$ 553,851
Subscription Settlement Costs (800 aMWs in $s)	$ 54,310	$ 54,310	$ 54,310	$ 54,310	$ 54,310	$ 271,550
Total Cost of Inventory Solution	**$ 417,144**	**$ 455,298**	**$ 418,621**	**$ 457,513**	**$ 444,959**	**$ 2,193,536**
Revenue 1112 aMWs flat, 450 aMWs to DSIs	$ (301,889)	$ (301,889)	$ (301,889)	$ (301,889)	$ (301,889)	$ (1,509,444)
Net Cost of Inventory Solution	**$ 115,255**	**$ 153,409**	**$ 116,732**	**$ 155,625**	**$ 143,071**	**$ 684,092**

	($000)
Annual Slice Revenue Requirement	**$ 1,657,672**
Monthly Slice Revenue Requirement	**$ 138,139**
One Percent of Monthly Requirement	**$ 1,381.39**

Five Year Total **$ 8,288,359**

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System Obligations include, but are not limited to, the transmission costs associated with the return of the Canadian Entitlement, and transactions related to the Pacific Northwest Coordination Agreement, Mid-Columbia Hourly Coordination, and the Canadian Non-Treaty Storage Agreement.

51. Total Plant Load

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period whether the customer has chosen to serve its load with BPA power or non-Federal power.

52. Total Retail Load (TRL)

Total Retail Load is all electric power consumption including distribution system losses, within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, Total Retail Load is called Total Plant Load.

53. Utility Distribution Company

A company that owns and maintains the distribution facilities used to serve end-use customers.

BPA's New 1996 General Rate Schedule Provisions for Power Rates

A. Targeted Adjustment Charge for Uncommitted Loads

1. Availability

The Targeted Adjustment Charge for Uncommitted Loads (TACUL) pertains to the PF rate schedule. The TACUL applies after December 7, 2000, to purchases to serve customer loads that were uncommitted during the 1996 rate case which are returned to BPA firm power requirements service during a period prior to FY 2002. Customers subject to the TACUL are those that reduced their purchases from BPA by adding firm resources to serve load under: (1) 1981 power sales contracts that expire on or before July 31, 2001, as may be amended; (2) Amendatory Agreement No. 7 (AA7) to the 1981 power sales contracts, or new ''1996'' power sales contracts where the customer provides BPA notice after December 7, 1998, consistent with the terms of the customer's power sales contract, for requirements service for the period prior to FY 2002. This charge will be in effect through September 30, 2001.

This rate schedule amends the PF–96 rate schedule, which went into effect October 1, 1996.

2. Energy Charge

The TACUL is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 1996 rate schedule, and is applied to that portion of the customer's load that is subject to the TACUL. The TACUL rate adjustment will be established based on the following formula:

TACUL = [(Incr $ * Incr Amt) − (Rate $ * Incr Amt)]/TACUL Amt

Where:

TACUL Amt = The amount of load subject to the TACUL, determined monthly.

Rate $ = The monthly PF energy rate shown in the applicable rate schedule.

Inventory Amt = Amount of energy available to serve this load based on an annual energy Federal system firm resource capability as defined in the Loads and Resources Study, and updated if BPA determines that is necessary.

Incr $ = Monthly cost to BPA, plus a handling fee, of incremental power for HLH and LLH expressed in mills/kWh (see below). These costs also may include where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the California PX.

Incr Amt = Amount of incremental power required, determined monthly and defined as the TACUL Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TACUL Amt).

Incr $ is greater than Rate $ (If Incr $ is less than Rate $, the TACUL is 0 mills/kWh).

TACUL is the monthly rate adjustment in mills/kWh. BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific Customer request. BPA will establish the cost of the additional power by the following methods:

a. BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market, or the monthly cost of BPA recallable power contracts, averaged, whichever is less.

b. A price plus handling fee calculated based on the following index.

BPA will calculate the price per month for HLH and LLH, based on an index calculated according to the following:

Price of HLH = ⅓ HLH (DJ Mid C) + ⅓ HLH (California PX) + ⅓ (NYMEX Mid C)

Price of LLH = ½ LLH (DJ Mid C) + ½ LLH (PX)

Where the California PX basis is adjusted to DJ Mid C

Where:

DJ Mid C = Dow Jones Firm On-peak (HLH) and Firm Off-peak (LLH) Mid-Columbia Electricity Price Index

California PX = California Power Exchange Day-Ahead Zonal Prices (Constrained)—the average of NW1 (Captain Jack/Malin—COB) and NW3 (NOB) for HLH and LLH

NYMEX Mid C = the New York Mercantile Exchange Futures Electricity Closing Price at Mid-C for the applicable month

California PX prices will be adjusted for basis difference between COB/NOB and the Mid-C using the IS/PTP Rates contained in BPA's 1996 Transmission Rate Schedules.

Issued in Portland, Oregon, on July 30, 1999.

Jack Robertson,

Deputy Administrator.

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DEPARTMENT OF ENERGY

Bonneville Power Administration

Proposed Correction of Errors in the Firm Power Products and Services Rate Schedule (FPS–96): Clarifying the Applicability of the FPS–96 Contract Rate to Certain Capacity With Energy Return Contracts, Public Hearing, and Opportunity for Public Review and Comment

AGENCY: Bonneville Power Administration (BPA), Department of Energy (DOE).

ACTION: Notice of Proposed Correction of Errors in the Firm Power Products and Services Rate Schedule (FPS–96): Clarifying the Applicability of the FPS–96 Contract Rate to Certain Capacity With Energy Return Contracts.

SUMMARY: BPA unbundled its wholesale power and transmission products in its 1996 rate case. Pursuant to this unbundling, several of BPA's wholesale power rate schedules included separate rates for sales of firm capacity with energy returns (commonly referred to as capacity without energy). Although clarifying language was mistakenly omitted from the FPS–96 rate schedule, the record established that it was BPA's intent that the firm capacity with energy returns product would be sold at a negotiated price.

Certain BPA contracts executed prior to October 1, 1996, provide that BPA supply capacity without energy at the demand charge in the Contract Rate of