DEPARTMENT OF ENERGY

Bonneville Power Administration

1996 Proposed Wholesale Power Rate and Transmission Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment

AGENCY: Bonneville Power Administration (BPA), DOE.

ACTION: Notice of proposed wholesale power rates and transmission rates.

SUMMARY: *BPA File No:* WP–96 and TR–96. BPA requests that all comments and documents intended to become part of the Official Record in this process contain the file number designation WP–96/TR–96.

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) provides that BPA must establish and periodically review its rates so that they are adequate to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, and to recover the Federal investment in the Federal Columbia River Power System (FCRPS) and other costs incurred by BPA.

By this notice, BPA announces its proposed 1996 wholesale power rates and transmission rates to be effective on October 1, 1996, including new 2- and 5-year rates. BPA also will publish a separate notice in the **Federal Register** of its new transmission services terms and conditions.

DATES: Written comments by participants relating to WP–96/TR–96 must be received by October 2, 1995, to be considered in the Draft 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 immediately above, (503) 230–4328 or call toll-free 1–800–622–4519. Information also may be obtained from:

Mr. Steve Hickok; Group Vice President, Sales and Customer Service, S–700; P.O. Box 3621; Portland, OR 97232 (503–230–5356).

Mr. George Eskridge; Manager, SE Sales and Customer Service District; 1101 W. River, Suite 250; Boise, ID 83702 (208–334–9137).

Mr. Ken Hustad; Manager, NE Sales and Customer Service District; Crescent Court, Suite 500; 707 Main; Spokane, WA 99201 (509–353–2518).

Ms. Ruth Bennett; Manager, SW Sales and Customer Service District; 703 Broadway; Vancouver, WA 98660 (360–418–8600).

Ms. Marg Nelson; Manager, NW Sales and Customer Service District; 1601 5th Avenue, Suite 1000; Seattle, WA 98101–1670 (206–216–4272).

Responsible Official: Mr. Geoff Moorman, Manager for Pricing, Marginal Cost and Ratemaking, is the official responsible for the development of BPA's rates.

SUPPLEMENTARY INFORMATION:

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I. Introduction and Procedural Background

Section 7(i) of the Northwest Power Act, 16 U.S.C. 839e(i), requires that BPA's wholesale power and transmission rates be established according to certain procedures. These procedures include, among other things, issuance of a **Federal Register** notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. As noted above, this rate proceeding to adjust wholesale power rates has been combined with the proceeding for BPA's proposal to adjust transmission rates. This proceeding is governed by BPA's rule for general rate proceedings, § 1010.9 of BPA's Procedures Governing Bonneville Power Administration Rate Hearings, 51 FR 7611 (1986) (hereinafter Procedures). These Procedures implement the statutory section 7(i) requirements. Section 1010.7 of the Procedures prohibits *ex parte* communications.

On December 28, 1994, BPA published a Notice of Intent to Revise Transmission Rates, 59 FR 66946 (1994), and Notice of Intent to Revise Wholesale Power Rates, 59 FR 66947 (1994). Subsequently, BPA published **Federal Register** Notices of Proposed Wholesale Power Rate Adjustment, 60 FR 8496 (1995), Proposed Transmission Rate Adjustment, 60 FR 8505 (1995), and Hearing and Opportunity for Public Comment Regarding Proposed Comparable Transmission Terms and Conditions, 60 FR 8511 (1995).

BPA's rate proceedings for 1995 and 1996, and the terms and conditions proceeding, began with a Prehearing Conference on February 13, 1995. The proceedings, originally in two dockets, WP–95/TR–95 (wholesale power and transmission rates) and TC–95 (transmission services terms and conditions), subsequently were separated into three different dockets as described below.

At the direction of the Hearing Officers at the February 13, 1995, prehearing conference, an additional prehearing conference was scheduled for March 15, 1995, and additional time was allowed for petitions to intervene. A **Federal Register** Notice for Additional Prehearing/Settlement Conference for March 15, 1995, 60 FR 11962 (1995), was published on March 3, 1995.

On February 14, 1995, BPA published a preliminary rate proposal in the **Federal Register**, 60 FR 8496. In that proposal, BPA noted that competitive forces are causing a fundamental and significant change in the Pacific Northwest wholesale power market. In light of these competitive forces, BPA determined that its initial proposal should include a 5-year rate as well as a 2-year rate. BPA anticipated that the work necessary to develop such a proposal would take until July 1995.

At the March 15, 1995, prehearing conference, the parties notified the hearing officers that they had been involved in negotiations for a settlement of issues that might affect the hearing schedule and requested additional time to complete the negotiations. The Hearing Officers acted on petitions to intervene received to that date and set a scheduling conference for March 22, 1995.

On March 17, 1995, most parties to the rate case signed a Settlement Agreement agreeing that BPA would propose to surcharge BPA's current rates for a 1-year period, October 1, 1995, through September 30, 1996, and to extend the Variable Industrial Power (VI) rate which was scheduled to expire on June 30, 1996, through September 30, 1996. The parties also agreed to conduct a separate subsequent process to establish a 2-year and a 5-year rate proposal, and a proposal for transmission services terms and conditions. The Settlement Agreement was an attempt to balance a number of interests, including concerns expressed by customer representatives to BPA's Power Sale Contract renegotiations.

In separate orders issued March 22, 1995, the Hearing Officers: (1) Adopted a service list for BPA's 1995 Wholesale Power and Transmission Rate Adjustment Proceeding, 1996 Wholesale Power and Transmission Rate Adjustment Proceeding, and 1996 Transmission Terms and Conditions Proceeding; and (2) ruled on other procedural matters concerning these proceedings. Copies of all orders, including the Order Establishing Schedules, may be obtained by contacting: Francis (Jamie) Troy, Hearing Clerk—LQ, Bonneville Power Administration, 905 NE. 11th Ave., P.O. Box 12999, Portland, Oregon 97212, (503) 230–4201.

In addition, the Hearing Officers ruled that intervenors who intervened in the dockets designated WP–95/TR–95 and TC–95 on or before March 15, 1995, were admitted as parties for all proceedings noted below.

As a result of the March 22, 1995, scheduling conference, the Hearing Officers issued an Order (the March 22 order) that divided the proceedings previously designated as WP–95, TR–95, and TC–95 into three separate dockets as follows:

A. The 1995 Wholesale Power and Transmission Rate Proceeding is designated WP–95/TR–95, and is a 90-day expedited rate proceeding conducted pursuant to Section 1010.10 of the Procedures. The proceeding began on May 1, 1995, when BPA issued its initial rate proposal and published it in the **Federal Register**, 60 FR 21132 (1995), and is scheduled to conclude on July 31, 1995, when BPA releases its Record of Decision (ROD). The proceeding proposes to extend current rates, including an extended VI rate, with a 4 percent surcharge, and establish the Southern Intertie Annual Cost rate and the Pacific Northwest Coordination Agreement (PNCA) rate.

B. The 1996 Wholesale Power Proceeding is designated WP–96 and the Transmission Rate Proceeding is designated TR–96, and both will be general rate proceedings conducted pursuant to Section 1010.9 of the Procedures. The March 22 Order established a hearing schedule beginning July 10, 1995, to establish BPA's power and transmission rates for the period beginning October 1, 1996, and new transmission services terms and conditions. The schedules adopted by the Hearing Officers for WP/TR–96 and TC–96 afford the parties a hearing process that encompasses a period of 8 months for establishment of BPA's new rate designs including new 2- and 5-year rates, and for establishment of transmission services terms and conditions.

C. The 1996 Transmission Services Terms and Conditions Proceeding is designated TC–96, and will be conducted pursuant to Section 1010.9 of the Procedures concurrently with WP–96/TR–96. The terms and conditions proceeding will be on the same schedule as the 1996 Wholesale Power and Transmission Rates proceedings.

BPA will file its 1996 initial rate proposal on July 10, 1995, and will publish its final ROD on April 30, 1996. The schedule established for WP/TR–96 provides an opportunity for interested persons to review BPA's proposed rates, to participate in the rate hearing, and to submit oral and written comments. Consideration of comments may result in a final rate proposal differing from the rates proposed in this notice.

II. Purpose and Scope of Hearing

BPA is planning significant changes in the design of its power rates. BPA is proposing to offer a 2-year and a 5-year power rate for requirements service. To address the increasingly competitive market for power and energy services, BPA is proposing to offer a menu of unbundled (or separately priced) products in the 1996 rate case. BPA expects that most of the products offered will be available both under current power sales contracts and under new power sales contracts. BPA expects to offer additional unbundled products in future rate cases and to price these products to meet market conditions and BPA's cost recovery obligations. In some cases, BPA expects the market will require flexible pricing. BPA is planning to ''unbundle'' what it offers so customers can choose among products and services based on what they need to meet their loads and support their own resources, if any. The services and products that customers may select to complement either firm requirements service provided by BPA, or power acquired from other sources, will be priced separately.

BPA has assessed the potential environmental effects of its rate proposal, as required by the National Environmental Policy Act (NEPA), as part of the Business Plan Environmental Impact Statement (EIS). The Draft Business Plan EIS was circulated for review and comment in July 1994. As a result of comments received, BPA prepared a Supplemental Draft Business Plan EIS, which was circulated for review and comment in February 1995. The Supplemental Draft Business Plan EIS evaluates several business structure alternatives. The analysis includes an evaluation of the environmental impacts of a range of rate design alternatives for BPA's power and transmission services, and an analysis of the environmental impacts of the rate levels resulting from the rates for such services under the business structure alternatives. BPA's initial rate proposal falls within the range of alternatives evaluated in the Final Business Plan EIS. Comments on the Business Plan EIS were received outside the formal rate hearing process, but will be included in the rate case record and considered by the Administrator in making a final decision establishing BPA's 1996 rates. The Business Plan EIS was completed in June 1995, and the Business Plan elaborating BPA's strategic action plans, will be released in the summer of 1995.

BPA's spending levels are developed as a part of its Business Plan, which includes a public comment process. They also are determined as a part of the Federal budget process. Consistent with the Draft Business Plan, the Administrator formally announced spending levels for Fiscal Years (FYs) 1996–2001 to the public on January 12, 1995. Since that time, BPA made the decision to reduce those spending levels by an average of $250 million per year for FYs 1996–2000. BPA currently is engaged in a budget process which will culminate in decisions on where these reductions will occur. BPA will continue to refine its strategic business objectives, goals, and spending levels, and inform the public accordingly, as part of its Business Plan development process. Therefore, except for the limited exceptions hereafter noted, spending level decisions will not be addressed in this rate case.

Pursuant to Section 1010.3(f) of the 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 in any way seek to visit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's cost evaluation period of FY 1996 through FY 2001 and its test period revenue requirement for FYs 1997 through 2001. If, and to the extent, any re-examination of spending levels is necessary, that re-examination will occur outside of the rate case.

BPA's Revenue Requirement Study will incorporate spending levels and reflect BPA's risk mitigation, capital funding, and other financial goals in the rates. 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) provision in BPA's revenue requirement for cash working capital or cash lag needs; (4) repayment matters such as interest rate forecasts, scheduled amortization, depreciation, replacements, and interest expense; and (5) updates to forecasts by BPA for which no other review forum has been provided.

Comparable Transmission Access

In the Energy Policy Act of 1992, Congress approved amendments to the Federal Power Act that allow FERC to order access to transmitting utilities', including BPA's, systems. As a result, FERC has proposed standards for providing comparable transmission access, including developing guidelines for pricing such access. ''Comparable'' refers to FERC's undue discrimination analysis which is now focused on a determination of whether the transmitting utility is offering third parties access on the same or comparable terms and conditions, and at the same or comparable rates that the utility uses for itself. On March 29, 1995, FERC issued a Notice of Proposed Rulemaking, ''Promoting Wholesale Competition Through Open Access Non-discrimination Transmission Services by Public Utilities,'' and Supplemental Notice of Proposed Rulemaking, ''Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,'' (NOPR). 70 FERC 61,351 (1995). In that NOPR, FERC proposed to require all public utilities subject to FERC jurisdiction to file generic open access tariffs and to take transmission service, including ancillary services, for their own new wholesale electric sales and purchases under the open access tariffs. The NOPR also includes a supplemental proposed rule to permit the recovery of stranded costs associated with requiring open access tariffs.

In a process concurrent with the 1996 rate case, BPA is proposing terms and conditions of general applicability for Network Integration and Point-to-Point transmission service that are modeled on the tariffs included in the NOPR. (For further information about the terms and conditions process, please contact Mr. Dennis Metcalf, Transmission Rates Manager, (503) 230–3410 or Mr. Michael Hansen, Public Involvement and Information Specialist, (503) 230–4328.) In conjunction with the proposed transmission services, this transmission rate proposal includes two new rate schedules (the Network Integration Transmission and Point-to-Point Transmission rates) that correspond to the new tariffs. In addition to being available to wheeling customers, BPA is proposing that its full and partial requirements customers will use these new comparable transmission services and associated rates for the transmission portion of their wholesale power purchases from BPA. BPA's proposed Energy Transmission rate schedule also will be used to price short-term firm and nonfirm service under the Point-to-Point Transmission Service Tariff. To the extent practicable, BPA is proposing a transmission construct under which the transmission cost associated with purchasing power from BPA is the same as that associated with purchasing non-Federal power. To this end, the segmentation of BPA's transmission system has been revised as described in Section IV.C, below. In response to the NOPR, BPA also will offer the Ancillary Products and Services and associated rates necessary for the transmission of power from resources to load on the FCRTS.

Stranded Investment, Cost Recovery Options, and Process for Regional Discussion

If BPA is to succeed in its power marketing objectives, its power must be marketable in both the short- and the long-run. While many factors influence the marketability of power, the single most important factor is price: BPA's power will not be marketable if it is priced above market. BPA has succeeded in marketing its power over the past 50 years because, while priced at cost, its power was priced at or below market. In fact, the impetus for the Northwest Power Act was the threat of an impending regional ''civil war'' of litigation among contenders for access to BPA's low-cost Federal hydropower. However, while BPA enjoyed a 400 percent price advantage in the early 1980's when the Northwest Power Act was passed, that price advantage now has largely disappeared.

As a consequence of these market considerations, BPA has cut its costs dramatically and is proposing rates in its 1996 rate case that are calculated to meet market demand, while comporting with statutory ratemaking requirements. At their most rudimentary level, rates are a function of costs divided by sales. Hence, assuming costs do not change, greater sales result in lower rates, and less sales mean higher rates. However, significantly higher rates also result in less sales. The sales that BPA has forecasted for purposes of setting its proposed 1996 rates is based on the assumption that BPA's power rates are competitive and will thus achieve BPA's marketing objective to retain sales and thereby stabilize rates and cost recovery.

The power rates that BPA is proposing in its 1996 rate case may be as high as they can be before BPA suffers significant sales loss. A critical issue in the 1996 rate case will be whether BPA's power rates for each customer class are at, above, or below that sustainable revenue point. Misjudgment on that issue could result in significant sales loss by BPA. BPA currently believes its proposed rates are set at a level that will indeed meet market demand.

If, however, customers reduce the amount of purchases they make from BPA significantly below the sales that BPA projected it would make when it set its rates, BPA runs a serious risk of revenue underrecovery. In previous proceedings establishing rates, BPA has factored risk of sales loss into its establishment of rates. Consequently, for the last 6 years BPA's power rates have included an Interim Rate Adjustment Clause or Cost Recovery Adjustment Clause (IRA) that would come into play and increase BPA's rates if they were not recovering BPA's costs. There were two primary reasons BPA's rates included these clauses. First, BPA's rate directives require that the Administrator establish rates based on BPA's total system costs and to assure repayment of the U.S. Treasury over a reasonable number of years. Second, market conditions enabled BPA to include these clauses in its power rates, *i.e.*, BPA's power rates were still viable after consideration of the clauses.

In its 1996 rate proposal, BPA has set its net revenues for risk to factor in the possibility of load loss, and it has not included an IRA or similar clause in its power rates. The reason is that the wholesale power market currently demands certainty and stability in price. Power prices without those features, *i.e.*, prices that are subject to change, will not be viable in the current power market.

If BPA experiences, or is faced with the possibility of sales loss, but cannot increase its rates directly or conditionally (such as through an IRA) to recover its costs, the issue arises of what actions BPA should take to prudently address the cost recovery problem. From a rates perspective, BPA has an obligation to establish its rates—power and transmission rates combined—to assure cost recovery, among other objectives. As discussed below, that would suggest the alternative of looking to transmission rates to assure cost recovery. From a broader perspective, the Northwest Power Act charges the Administrator with the responsibility of implementing the Act in a sound and business-like manner. That would suggest consideration of not just rate alternatives, but other alternatives as well, such as alternatives that might moderate sales loss in an amount that would not be significant to the degree of resulting in a BPA cost underrecovery.

BPA does not have a specific proposal concerning this issue to make at this time for purposes of the 1996 wholesale power and transmission rates proceedings. This issue is of such critical importance to BPA's cost recovery, its various statutory missions, its business relationship with its customers, and its relationship with non-customers such as fish and wildlife interests, that BPA believes it would be intolerable if, without the benefit of advance regional discussion, it were to make a formal rate case proposal and then limit dialogue on the issue by taking comment only through the formal process of the rate case. If the appropriate solution to the problem turns out to be a rates solution, prudent business judgment dictates that BPA first should have engaged its customers and interested third parties in a consensus-seeking dialogue on the issue. The dialogue should be sufficiently long to consider and evaluate parties' opinions with a view to forging consensus, and short enough to integrate the results of the discussions in the Administrator's final establishment of rates at the conclusion of this rate case, if that is necessary.

Consequently, BPA hereby advises interested parties that it is discussing this cost recovery issue with its customers and interested third parties throughout the region. Initial discussions already have occurred in the context of negotiations over new power sales contracts. Parties wishing to be advised of future public discussions should contact BPA Corporate Communications at the address listed in Section I of this notice. BPA anticipates that discussions on rate options will conclude by the end of July or early August 1995. In the event the discussions result in a rate proposal by BPA, concluding discussions by the beginning of August should enable BPA to prepare and publish its rate proposal by October of 1995. The ensuing section 7(i) process would be timed to conclude so that the outcome could be integrated into the rates finally established at the conclusion of BPA's 1996 wholesale power and transmission rate proceedings. Consequently, pending resolution of this cost recovery issue, all transmission and wholesale power rates proposed at this time should be considered subject to a possible cost recovery adjustment.

Apart from the possibility of some sort of a negotiated phased load loss or other contractual solution that avoids the cost recovery problem, BPA currently is considering two rate options to deal with the cost recovery issue. Each option is described below. The descriptions are provided not as a BPA proposal, but rather to enhance understanding of the issues and the expected discussion of them.

In the first rate option, BPA would designate a portion of its proposed power rates as a charge to mitigate the revenue exposure BPA faces from potential loss of sales to alternative suppliers. All customers would pay that amount whether they continued to purchase power from BPA or not. The charge would be collected from utility customers that leave BPA in whole or in part, by terminating or by reducing their load on BPA through Section 12 of the utility power sales contract, and from Direct Service Industry (DSI) customers that reduce or eliminate load on BPA for any reason under the DSI contracts. For example, the amount could be 2 mills of a proposed 24 mill power rate—the assumption being that, if the customer purchasing at 24 mills departs, BPA may only recover 22 mills, leaving 2 mills ''stranded.'' This stranded cost component would be applied to the rates of all power customers, similar to a customer charge. If the customer decides to depart, then the customer may avoid the 22 mill power rate but would continue to pay the 2 mill customer charge on the transmission component of the departing customer's power rates (if the customer continues to purchase some part of its requirements from BPA) and wheeling rates. BPA' DSI customers may be anticipated to argue that this option runs counter to their contractual rights to take load off BPA on 1 year's notice if they pay BPA ''unrecoverable costs'' as defined through their contractual relationship with BPA.

The second rate option (the cost recovery surcharge option) takes a different approach. This option does not target recovery only from customers that terminate their contracts or reduce their load, but rather would directly or conditionally impose a ''cost recovery'' surcharge on the transmission or wheeling rates of all existing and former power customers regardless of their then-current purchasing status. This approach is premised on the fact that BPA is obligated to recover all costs, not just those that are ''stranded'' by departing customers. The basis for the transmission surcharge in this option is that it is designed to recover costs that otherwise cannot be recovered through power rates, from all customers that have benefited from the power system, consistent with BPA's statutory obligation.

The cost recovery surcharge would recover the amount of costs that, while otherwise properly allocable to power rates, cannot be recovered in a timely fashion through power rates. The surcharge would be developed in a manner that is equitable in relation to past power usage by BPA's requirements power customers in the Pacific Northwest, including residential exchange power customers. Such equitability could be, but would not necessarily be, achieved as follows: A first step would be to determine the average annual amount of Federal power purchased by each requirements power customer of BPA during the period 1980 to 1994 or some other relevant period. All customers' annual average purchases then would be summed, and each customer's percentage share of the total would be determined. Each individual customer's percentage then would be multiplied by the total amount of the cost recovery surcharge amount (an amount that would vary with BPA load loss) to determine the customer's surcharge recovery responsibility. The adder to transmission rates could be designed to assure that each customer directly or indirectly pays the amount of its surcharge responsibility.

Under both options, the payment could be indirect where the customer is served only by another power supplier that uses the FCRTS for any purpose. In that case, the power supplier would be assessed the surcharge or customer charge by BPA, with the expectation that the power supplier would recover the cost from the former BPA power customer. Power suppliers falling into that category are hereby put on notice of the possibility that BPA may levy such a charge. This notice is provided in the event they wish to structure pricing arrangement with the customer that fully recovers, or pass through, BPA's transmission charge.

III. Public Participation

The procedural history of this rate proceeding is described in Section I, above. Petitions to intervene as parties have been received and acted upon by the Hearing Officers.

BPA continues to conduct workshops on subjects relevant to its ratemaking. The purpose of the workshops is to identify, simplify, and reduce the number of issues that might become part of the 1996 rate case, and to reduce the amount of discovery normally required during the formal rate proceedings.

Opportunity is provided for workshop participants to address the impacts of BPA's proposed 5-year rate, transmission issues, risk mitigation, and rate design issues. The workshops provide opportunity for informal public comment on issues prior to the formal hearing process.

BPA's procedures allow submission of comments, views, opinions, and information from ''participants,'' who are defined in the Procedures as any person who may express views, but who does not petition successfully to intervene as a party. Participants' written comments will be made part of the official record of the case and considered by the Administrator. The participant category gives the public the opportunity to participate and have its views considered without assuming the obligations incumbent upon ''parties.'' Participants are not entitled to participate in the prehearing conference, 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 Draft ROD if they are received by October 2, 1995. 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 Addresses Section of this notice. In addition, BPA will hold several public field hearings in the Pacific Northwest Region.

Public field hearings are an opportunity for participants to have their views included in the official record. Participants may appear at the field hearings and present oral testimony. Written transcripts will be made at all of the field hearings. The transcripts of these hearings will be part of the record upon which the Administrator makes final rate decisions. Following are the tentative dates and locations for the field hearings. All of the field hearings are scheduled to begin at 7 p.m. Registration begins at 6:30 p.m. Confirmation of these hearing dates and times will be made through mailings and public advertising or by calling BPA Corporate Communications at the telephone number listed in Section I above.

September 19, 1995
Best Western Burley Inn, 800 N. Overland Avenue, Burley, Idaho 83318

September 20, 1995
Cavanaugh's, Ballroom B, 200 North Main, Kalispell, Montana 59901

September 21, 1995
Red Lion GateWay, 3280 Gateway Drive, Springfield, Oregon 97477

September 26, 1995
Howard Johnson Plaza Hotel, Whidbey-Camano Room, 3105 Pine, Everett, Washington

September 27, 1995
Cavanaugh's, East 110 Fourth Avenue, Spokane, Washington 99202

September 28, 1995
Pasco Red Lion, Design Room, 2525 North 20th, Pasco, Washington 99301

The record will include, among other things, the transcripts of any hearings, any written material submitted by the parties and participants, documents developed by BPA staff, BPA's environmental analysis and comments accepted thereon, 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 a decision.

The Administrator will develop final 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 rates first will be expressed in the Administrator's Draft ROD. Parties will have an opportunity to comment on the Draft ROD as provided in BPA's hearing procedures. The Administrator will serve copies of the Final ROD on all parties and will file the final wholesale power and transmission rates together with the record with the Federal Energy Regulatory Commission (FERC) for confirmation and approval. Consideration of comments and more current data may result in the final rates differing from the rates proposed in this Notice.

Because of the complexity of the issues in this rate case, in part occasioned by continuing contract negotiations between BPA and its customers, as well as BPA's ''reinvention'' and Competitiveness Project, BPA anticipates that it will need to meet with customers and other interested third parties during the rate case on a very frequent, and possibly extended, basis. 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.

IV. Major Studies

The studies that have been prepared to support the 1996 initial proposal will be served on all parties of record and will be available for examination on or about July 10, 1995, at BPA's Public Information Center, BPA Headquarters Building, 1st Floor, 905 NE. 11th, Portland, Oregon. The studies and documents are:

A. Loads and Resources Study and Documentation
B. Revenue Requirement Study and Documentation
C. Segmentation Study
D. Marginal Cost Analysis Study and Documentation
E. Wholesale Power Rate Development Study and Documentation
F. Section 7(b)(2) Rate Test Study and Documentation
G. Transmission Rate Design Study
H. Wholesale Power and Transmission Rate Schedules

To request any of the above documents by telephone, call BPA's document request line: (503) 230–3478 or call toll-free 1–800–622–4520. Please request the document by its above-listed title. Also state whether you require the accompanying documentation (these can be quite lengthy); otherwise, the study alone will be provided. (For example, ask for the ''Revenue Requirement Study and Documentation.'')

A. Loads and Resources Study

BPA's forecasts of regional loads by customer group are the basis from which public utility and DSI customer purchases from BPA (Federal system firm loads) are projected. BPA also projects Federal transmission losses, obligations to regional investor-owned utilities (IOUs) under their power sales contracts, and other inter- and intraregional contractual obligations.

BPA develops forecasts of regional non- and small-generating public utility (NSGPU) and generating public utility (GPU) loads using standard econometric techniques. Regional NSGPU and GPU loads are forecasted as a function of average retail electricity prices, weather-related variables, and nonagricultural employment. The regional load forecasts then are adjusted to account for factors such as effects from conservation programs and utility purchases from alternative (non-BPA) power suppliers to derive a projection of NSGPU and GPU purchases from BPA. The IOU load forecast was produced by updating the economic assumptions from the 1991 joint BPA/Northwest Power Planning Council (NPPC) forecast.

Forecasts of aluminum DSI purchases from BPA are prepared by analyzing smelter production costs relative to aluminum prices, and by considering other factors affecting smelter loads, including DSI purchases from alternative (non-BPA) power suppliers. Forecasted non-aluminum DSI purchases from BPA are prepared by analyzing historical and technical plant information, forecasted market conditions, and potential purchases from alternative power suppliers.

The ratemaking load/resource balance represents BPA's projected service to firm loads during the test years under 1930 water conditions. The ratemaking load/resource balance is used in the calculation of the supply of surplus firm power in the region and on the Federal system during the test period. A related hydro regulation study incorporates the operation of thermal plants, exports and imports of power, projected resource acquisitions, and system constraints such as ''flow augmentation'' for fish mitigation. For this proposal, a 50-year hydro study was completed, which includes assumptions regarding the flow augmentation. The hydro study starts in August 1995. The 50-year study determines expected nonfirm energy availability for the region based on 50 years of streamflow data.

B. Revenue Requirement Study

The BPA Project Act, the Flood Control Act of 1944, the Transmission System Act, and the Northwest Power Act require BPA to set rates that are projected to collect revenues sufficient to recover the cost of acquiring, conserving, and transmitting the electric power that BPA markets, including amortization of the Federal investment in the FCRPS over a reasonable period, and to recover BPA's other costs and expenses. The Revenue Requirement Study includes a demonstration of whether current rates will produce enough revenues to recover all BPA costs and expenses, including BPA's repayment requirements to the U.S. Treasury. Revenue requirements are a major factor in determining the overall level of BPA's proposed power and transmission rates.

The Transmission System Act and the Northwest Power Act require that transmission rates be based on an equitable allocation of the costs of the Federal transmission system between Federal and non-Federal power using the system. Separate generation and transmission revenue requirements are developed in the Revenue Requirement Study. In compliance with a FERC order dated January 27, 1984, 26 FERC ¶ 61,096, the Revenue Requirement Study incorporates the results of separate repayment studies for the generation and transmission components of the FCRPS. The repayment studies for generation and transmission demonstrate the adequacy of the projected revenues at proposed rates to recover the Federal investment in the FCRPS over the allowable repayment period. The adequacy of projected revenues to recover test period revenue requirements and to meet repayment period recovery of the Federal investment is tested and demonstrated separately for the generation and transmission functions.

The Revenue Requirement Study for the 1996 Initial Rate Proposal is based on cost and revenue estimates for FYs 1997–2001. The cost estimates include an undistributed reduction averaging $250 million for each year. This reflects BPA's decision to reduce revenue requirements to enable it to set rates at a level which recovers its costs but also meets current market conditions (although specific program and/or organizational spending cuts have not been finalized). This study also includes planned net revenues to mitigate financial risk, to ensure that cash flows are adequate to demonstrate timely repayment of the Federal investment including irrigation assistance, as well as to finance a portion of BPA's capital investments. BPA's Revenue Requirement Study reflects actual amortization and interest payments paid through September 30, 1994. In addition, it reflects all FCRPS obligations incurred pursuant to the Northwest Power Act, including residential exchange program costs.

Also part of the Revenue Requirement Study is a risk analysis that evaluates the impact that various economic and generation resource capability conditions could have on BPA's ability to make annual U.S. Treasury payments during the rate test period. The risk analysis measures the financial risks surrounding the revenue and expense forecasts used to set rates. It also is used to determine the amount of cash required for risk that is needed to meet the target Treasury payment probability, and is used to determine the Treasury payment probability resulting from inclusion of cash for risk in the revenue requirement.

C. Segmentation Study

BPA operates and maintains the FCRTS to provide transmission services throughout the region. Because most services do not require the use of the entire system, BPA has historically segmented the FCRTS into nine segments, each providing a distinct type of service. The nine segments are: integrated network; Fringe; Pacific Northwest-Pacific Southwest (Southern) Intertie; Northern Intertie; Eastern Intertie; generation integration; and delivery segments for public agency, DSI, and IOU customers. Although BPA is proposing different segmentation in its initial rate proposal, the Segmentation Study for the initial rate proposal will maintain the historic segments. Re-segmentation of the revenue requirement for the initial proposal will be done as part of the Transmission Rate Design Study.

The Segmentation Study categorizes the facilities of the FCRTS according to the types of services BPA provides on such facilities. This provides the basis for segmenting the projected transmission revenue requirements used in BPA's rate proposals. The results of the Study include the historical investment and the average of the last 3 years' operations and maintenance expenses. In addition, the facilities of the integrated network are divided among distinct services for use in developing the Formula Power Transmission rate. This division of the FCRTS into segments provides the basis for the equitable allocation of transmission costs between Federal and non-Federal customers based on their usage of the segments.

In this proceeding, BPA proposes to reclassify the BPA transmission facilities formerly classified as fringe to the network segment to reflect the realignment of the transmission business. In addition, the former IOU Delivery segment is now included in the network segment. The definition of Delivery facilities also has been revised. BPA plans to reflect these changes to segmentation in the Segmentation Study in the supplemental rate proposal.

D. Marginal Cost Analysis

The Marginal Cost Analysis (MCA) estimates the marginal cost that BPA incurs to supply peak demand on heavy load hours, and energy on a seasonal, daily, and hourly basis to meet customers' loads. The conditions and terms under which BPA supplies energy necessitate that BPA take actions that impose a cost. The MCA measures the costs that BPA incurs in taking actions to provide energy under different terms.

BPA proposes to measure the marginal costs of actions it takes to: (1) Guarantee availability of energy; (2) guarantee a maximum rate of delivery of energy (demand); (3) provide energy at guaranteed prices; and (4) actually deliver energy. The results of the MCA are used to develop wholesale power rates that promote efficient development and operation of generation and conservation resources.

BPA proposes to measure marginal costs based on the conditions BPA faces in the interconnected West Coast wholesale power market. Estimated marginal costs are based on the results from a model that was developed to simulate future wholesale market transactions to aid in BPA's long-term power marketing and resource strategy decisions—the Power Marketing Decision Analysis Model (PMDAM). PMDAM projects the marginal costs that BPA will face when taking actions to serve its Pacific Northwest customers, at the least cost, under conditions of uncertainty. PMDAM uses information on the costs associated with acquiring and operating resources to meet load in conjunction with the costs associated with purchasing and/or selling power in the West Coast bulk power market.

The MCA provides estimates of BPA's marginal costs of supplying peaking demand on heavy load hours, and energy at different times. These estimates provide the basis for determining the generation component of BPA's demand charge. The estimates also provide the basis for the seasonal and hourly time-differentiation of energy charges, including the identification of time-periods in which different rates may apply and appropriate levels for rates in each time period relative to the others. These time periods consist of hours of the week when the marginal cost of power is high and those when it is relatively low, as well as seasons of the year when different marginal costs prevail. The results of the analysis suggest that BPA's rates be different for six seasons. The results also suggest that BPA's energy rates be differentiated between heavy and light load hours, which was not a feature of previous rate designs. The analysis does not include any quantitative estimate of marginal costs incurred on the transmission system.

E. Wholesale Power Rate Development Study (WPRDS)

BPA is proposing substantial changes in the method used to develop its wholesale power rates. BPA's wholesale power rate development is a two step process. First, BPA allocates the test period generation revenue requirements and then adjusts these results to reflect various rate design objectives and statutory requirements.

1. Allocation of BPA's Generation Revenue Requirements

BPA allocates the test year generation revenue requirements to customer classes based on the use of specific services by each customer class and the rate directives of the Northwest Power Act.

BPA is proposing to recognize three different categories of generation costs as part of its effort to unbundle generation services: peak demand, rights to energy, and delivered energy. Generation energy cost allocations reflect the relative use of services and resources needed to serve load. Costs recovered from the sales of peak demand and rights to energy products are treated as a credit against BPA's generation costs prior to allocating the generation revenue requirements.

2. Adjustments to Allocated Costs

The remaining steps in the rate design process use the allocated costs developed in the Cost of Service Analysis (COSA) and modify them to: (1) reflect BPA's rate design objectives; (2) conform with contractual requirements; (3) reflect the results of other BPA studies and commitments made in other public involvement processes under Section 7(i) of the Northwest Power Act; and (4) conform with requirements of applicable legislation. BPA's rate design objectives include recovery of BPA's revenue requirement, rate and revenue stability, practicality, fairness, and efficiency.

Major rate design adjustments to the allocated COSA costs include the following:

a. Excess Revenue Adjustment

In the initial cost allocation, BPA allocates its entire test period revenue requirement to firm power loads on the basis of resources available under critical water conditions. However, rates are set assuming BPA recovers nonfirm sales revenues equal to the expected value of revenues under 50 years of streamflows in the historical record. Because no generation costs are allocated to nonfirm energy (NF) service, the generation portion of forecasted NF revenues are credited against costs allocated to firm loads.

b. Surplus Firm Power Excess Revenue Adjustment

BPA has sold and expects to continue to sell surplus power under long-term contracts. Expected revenues from the sale of such power are compared to allocated costs. BPA expects revenues to exceed costs of this power, resulting in a credit to other customers.

c. 7(c)(2) Adjustment

The rates applicable to the DSIs are set according to the rate directives contained in Section 7(c) of the Northwest Power Act. In 1987, BPA adopted a methodology for setting the DSI rate known as the IP-PF (Industrial Firm Power-Priority Firm Power) rate link. The link is essentially a formula that quantifies the rate directives. The components of the formula are the typical margin, a character of service adjustment, a value of reserves credit, and an inflation adjustment. The link has been used to set rates since the 1987 rate case. However, it will expire with the expiration of the current VI rate contract on September 30, 1996, and cannot be used to set rates in this rate proceeding.

Therefore, BPA is recalculating the factors of the link. The first factor is the typical margin that BPA's preference customers include in their retail industrial rates. The second factor is the character of service adjustment that accounts for the fact that a portion of the DSI load is not served as firm on a planning basis. The third factor is the credit that reflects the value of reserves provided to BPA by its restriction rights on the DSI load. In this proposal an inflation adjustment is not included because its purpose in the current link is to escalate the other factors to each rate case so they do not have to be recalculated. It is not necessary to include an inflation adjustment because new values are being determined in this rate proceeding.

Using the factors described above, a DSI rate calculation is performed that links it to the preference customer rate. The revenues from this linked DSI rate are less than the costs initially allocated to the DSIs. The difference is called the ''7(c)(2) delta'' and is allocated to other power customers.

The foregoing list of rate design adjustments identifies some of the major cost adjustments and is not intended to be all-inclusive. As a final step in rate design, BPA develops seasonal and diurnally differentiated energy charges based on allocated costs and scaled based on the results of the MCA. The final step in the WPRDS is to combine the revenues projected for energy, capacity, rights to energy, and transmission. These total revenues by customer class are divided by the relevant billing determinants to calculate average rates.

3. Changes in Rate Design

A major change that BPA is proposing is the introduction of separate 5-year duration rate schedules for PF, IP, and NR rates. Other rate design changes include the elimination of an Interim Rate Adjustment, changes to demand charges, development of a composite rate for some small customers, changes to the Low Density Discount, elimination of the Irrigation Discount, changes to the unauthorized increase charge, changes to the NF contract rate, and development of a rate phase-in adjustment for full or metered requirements customers.

a. 5-Year Rate

BPA is proposing to introduce a 5-year rate, available by subscription for all purchasers under the PF, IP, and NR rate schedules. The 5-year duration is available for power purchases, as well as related unbundled products, to purchasers under both the current and new power sales contracts. The longer-term rate is intended to provide customers with price certainty for the products needed to supply their entire electricity portfolio. BPA will continue to offer a 2-year rate for products and services. The 5-year rate will have the same seasonal and diurnal shape as the 2-year rate, and will be constant over the 5-year period. In most cases, customers will be able to choose to place a portion of their load on the 2-year rate and a portion on the 5-year rate. Utilities serving New Large Single Loads (NLSLs) must elect to have their NLSLs served at either the 2-year or the 5-year rate. The 5-year rate will not be available to utilities participating in the exchange under section 5(c) of the Northwest Power Act.

b. Power Demand Charges

BPA is proposing a number of changes to the demand charge. Customers will be billed for transmission service for their Federal power deliveries, assessed under the appropriate transmission rate schedules. Further discussion of the proposed transmission rates is in Section E, below. There also will be a ''generation'' demand charge in the PF, IP, NR, and FPS rate schedules. This charge will be assessed to power purchases that occur during the same hour as the transmission system peak. BPA has proposed to eliminate the Demand Ratchet included in previous rate cases. It has not proved to be effective, and with the other demand rate design changes, is unnecessary.

c. The Composite Rate

A composite rate is being proposed for utility purchasers who choose to purchase their entire power requirements from BPA at the composite rate under the PF–96.5 rate schedule. Only customers whose forecasted average annual energy loads during the 5-year purchase period are 25 average annual megawatts or less are eligible to purchase at this rate. The composite rate is a weighted average rate based on the relative cost of generation demand, energy, load shaping and load regulation. Customers will be billed for transmission service for their Federal power deliveries, assessed under the appropriate transmission rate schedules.

d. Low Density Discount

BPA is proposing to change the eligibility criteria and calculation of the Low Density Discount. In determining eligibility, the total electric energy requirement now will include nonfirm sales to firm retail and nonfirm loads. The calculation proposes using a sliding scale of percentage discounts based on both (1) the utility's number of customers per pole-mile and (2) the utility's ratio of total electric energy requirements to investment. Separate discounts resulting from each of the two ratios will be added to result in the utility's total discount, which is capped at 7 percent. The proposed discount will apply to total power purchases under both current and new power sales contracts, and will not apply to transmission-related charges.

e. Unauthorized Increase for Power Sales

BPA proposes to change the unauthorized increase charge to eliminate seasonal differentiation. This reflects treating the charge as a penalty rate, applicable to purchasers taking demand and energy in excess of their contractual entitlement, rather than a cost-based rate. This unauthorized increase charge will apply both to current and new power sales contracts. In addition, there is an unauthorized deviation charge for partial requirements purchases purchasing under the new power sales contract. This rate is the same as the unauthorized increase charge.

f. Nonfirm Rate Schedule Contract Rate

BPA also is proposing to modify the contract rate in the NF rate schedule. The contract rate will be equal to the average cost of nonfirm energy.

g. Rate Phase-in Adjustment

BPA is proposing a rate phase-in mitigation for full or metered requirements preference customers, who, as a result of all of BPA's rate design changes, will see a rate increase greater than 9 percent. This phase-in adjustment is available only to customers who choose to purchase all of their power from BPA at the 5-year rate, and meet other eligibility requirements.

4. Unbundled Products

For service under both the 1981 and 1996 power sales contracts, BPA is proposing separate charges under the PF, IP, and NR rate schedules for firm energy demand, load shaping, partial load shaping, and load regulation. Load shaping allows BPA to meet customer load variations from forecasts. Load regulation follows variations in the customers' loads on an instantaneous basis. BPA is unbundling, i.e., separately pricing, many products, generally available under two new rate schedules.

5. Ancillary Services

BPA is proposing the Ancillary Products and Services (APS) rate schedule for those services necessary to support the transmission of electric power from resources to load on the FCRTS. These services are: control area reserves for resources; control area reserves for interruptible purchases; scheduling and dispatch; load regulation, and transmission losses.

6. Firm Power Products and Services

BPA also has developed the Firm Power Products and Services (FPS) rate schedule. The FPS rate schedule will allow BPA to sell firm energy, capacity, or power using a variety of sources of supply, and will specify charges or specifically authorize negotiated charges for various unbundled products. Firm power products and services to be marketed by BPA under the FPS rate schedule are intended to be flexible so that BPA can respond to market conditions.

F. 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 4 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) rate test implementation methodology.

The rate projections and the actual rate test itself are performed using BPA's Supply Pricing Model (SPM). The SPM simulates BPA's rate development process, using load, resource, and cost data consistent with that used in this rate proposal. The SPM calculates two sets of wholesale power rates for BPA's preference customers: (1) a set of rates for the test period and the ensuing 4 years, assuming that Section 7(b)(2) is not in effect (program case rates); and (2) a set for the same period considering the five assumptions listed in Section 7(b)(2) (7(b)(2) case rates). Certain costs specified in Section 7(g) of the Northwest Power Act (7(g) costs) are subtracted from the program case rates.

The SPM then discounts each year's rates to the test year of the relevant rate case, averages each set of discounted rates, and compares the two resulting averages rounded to the nearest tenth of a mill. If the average of the discounted program case rates, less the 7(g) costs, is larger than the average discounted 7(b)(2) case rates, the rate test triggers. If the rate test triggers, the amount of dollars to be reallocated in the test period (7(b)(2) amount) is calculated by multiplying the difference between the discounted program case and 7(b)(2) case rates by the general requirements loads of the preference customers. The 7(b)(2) amount, if any, is used as an adjustment to the allocated costs in the rate case test period.

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

G. Transmission Rate Design Study (TRDS)

For the first time, rates for Federal and non-Federal use of the transmission system are developed in the TRDS. BPA's construct in developing the proposed transmission rates is to make transmission services available to power customers, wheeling customers, and its own power business at the same terms, conditions, and rates.

The transmission service required for BPA power sales is offered under the new Network Integration (NT) rate and Point-to-Point (PTP) rate. These rates also are available for transmission of non-Federal power. BPA's full requirements customers must take transmission service at the NT rate; other BPA power customers may choose the NT or PTP rate. Consistent with the power rates, 2-year and 5-year NT and PTP rates have been developed. The 2-year NT and PTP rate may be used by power customers only if they are not purchasing power under the 5-year power rates. The remaining transmission rates are developed for a 2-year rate period only.

As part of implementing the transmission rate construct, the segmentation of BPA's transmission system also is being revised: BPA transmission facilities formerly in the Fringe now are included in the Network segment. Facilities at 34.5 kV and below are classified now as Delivery; facilities that are above 34.5 kV are segmented to the Network. Charges for Utility Delivery and DSI Delivery are developed in the TRDS to apply to all power delivered over these facilities. This new segmentation is performed in the TRDS for the initial rate proposal; the Segmentation Study should reflect the new segmentation in the supplemental proposal.

To calculate rates in the TRDS, the segmented transmission revenue requirements are allocated to Federal and non-Federal power forecasted to use the FCRTS. The factors for allocating Network cost to loads are the billing determinants for the Network transmission services. Prior to allocating Network cost, BPA identifies the cost associated with transmission load shaping, a feature of Network Integration service, and removes it from Network cost. After allocation, this transmission load shaping cost is added to the costs to be recovered from the NT rate. Southern Intertie and Northern Intertie costs are allocated based on forecast energy use.

Rate charges based on the allocated costs are calculated, and individual rate schedules are designed. In addition to the NT and PTP rates, all of BPA's traditional rates are calculated. BPA also is proposing the Advance Funding rate to allow BPA to recover the cost of specified transmission facilities through advance payment. Finally, BPA is proposing a Reservation Fee for Transmission Capacity, and a Reactive Power Charge that takes the place of the current Power Factor Adjustment.

V. Wholesale Power Rate Schedules and Transmission Rate Schedules

A. Introduction

The rate schedules are divided into three sections. The first section (Section C below) contains the wholesale power rate schedules. The second section (Section D below) contains the transmission rate schedules. The third section (Section E below) is the combined GRSPs for power and transmission rates.

The proposed wholesale power and transmission rate schedules were prepared in accordance with BPA's statutory authority to develop rates, including the BPA 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).

The 1996 proposed wholesale power and transmission rate schedules and the GRSPs associated with those rate schedules will supersede BPA's 1995 rate schedules (which BPA proposes to become effective October 1, 1995) to the extent stated in the Availability section of each 1996 rate schedule. BPA proposes that its wholesale power and transmission 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, 1996.

B. Summary of Wholesale Power Rate Schedules

WHOLESALE POWER RATE SCHEDULES

PF–96	Priority Firm Power Rate.
NR–96	New Resource Firm Power Rate.
IP–96	Industrial Firm Power Rate.
VI–96	Variable Industrial Power Rate.
NF–96	Nonfirm Energy Rate.
RP–96	Reserve Power Rate.
PS–96	Power Shortage Rate.
FPS–96	Firm Power and Services Rate.
APS–96	Ancillary Products and Services Rate.

A summary of the proposed 1996 Wholesale Power Rate Schedules is provided below. Each rate schedule includes sections specifying the customer class and the service available under the rate schedule, the rates for the products and services offered under the schedule, the applicable billing factors, applicable transmission rate schedules, and other special provisions for rate adjustments, such as any discounts or penalties that apply to that rate schedule.

1. Priority Firm Power Rate (PF–96.2 and PF–96.5)

The proposed PF–96.2 rate schedule would be available for a 2-year period beginning October 1, 1996, and would replace the PF–95 rate schedule. The proposed PF–96.5 rate schedule would be available for a 5-year period beginning October 1, 1996. Power is available under the proposed PF–96 rate schedule to public bodies, cooperatives, and Federal agencies. Utilities participating in the residential exchange under section 5(c) of the Northwest Power Act may purchase power only under PF–96.2. Priority Firm power must be used to meet firm loads within the Pacific Northwest. The proposed PF rate consists of seasonally and diurnally differentiated energy charges, and charges for demand, load shaping, load regulation, and transmission. Rate adjustments include a Conservation Surcharge, Low Density Discount, Energy Return Surcharge, Deviation Adjustment, Phase-In Mitigation, Preschedule Change Charge, Reactive Power Charge, Transitional Service, Unauthorized Increase, and Industrial Exemption and Curtailment.

2. New Resource Firm Power Rate (NR–96.2 and NR–96.5)

The proposed NR–96.2 rate schedule would be available for a 2-year period beginning October 1, 1996, and would replace the NR–95 rate schedule. The proposed NR–96.5 rate schedule would be available for a 5-year period beginning October 1, 1996. The proposed NR–96 rate schedules are available to investor-owned utilities under net requirements contracts for resale to consumers, and to publicly owned utilities for New Large Single Loads. The proposed NR rate consists of seasonally and diurnally differentiated energy charges, and charges for demand, load shaping, load regulation, and transmission. Rate adjustments include a Conservation Surcharge, Low Density Discount, Energy Return Surcharge, Deviation Adjustment, Phase-In Mitigation, Preschedule Change Charge, Reactive Power Charge, Transitional Service, and Unauthorized Increase.

3. Industrial Firm Power Rate (IP–96.2 and IP–96.5)

The proposed IP–96.2 rate schedule would be available for a 2-year period beginning October 1, 1996, and would replace the IP–95 rate. The proposed IP–96.5 rate schedule would be available for a 5-year period beginning October 1, 1996. The proposed IP–96 rate schedules are available to BPA's DSI customers for firm power to be used in their industrial operations. The proposed IP rate consists of seasonally and diurnally differentiated energy charges, and charges for demand, load shaping, load regulation, and transmission. Rate adjustments include a Conservation Surcharge, Curtailment Charge, Deviation Adjustment, First Quartile Discount, Operating Reserves Credit, Preschedule Change Charge, Reactive Power Charge, and Unauthorized Increase.

4. Variable Industrial Power Rate (VI–96)

The proposed Variable Industrial Power (VI–96) rate schedule would replace the VI–95 rate. The proposed VI–96 rate is available to BPA's DSI customers who enter into a separate variable rate contract with BPA for power to be used in their aluminum and nickel smelting operations. Purchasers under this rate schedule must first elect service under the proposed IP rate schedule for either the 2-year period or the 5-year period, both beginning October 1, 1996. The variable rate will be based on the IP rate under which the purchaser has elected service. The demand charge for the variable rate will be the same as in the applicable IP rate, but the monthly energy charge will vary with the price of the metal used in the purchaser's smelting operation. Because BPA plans to hedge the risk of aluminum or nickel price fluctuations, individualized variable rates will be designed at the time each purchaser enters into a variable rate contract. The contracts will be designed so that BPA will receive revenues, either from the DSI or the hedging financial institution, equal to those that would be received under the IP–96 rate schedule. The purchaser can choose to have an initial variable rate formula in effect for any period from 1 to 2 years under the 2-year rate option or from 1 to 5 years under the 5-year rate option. At the expiration of the rate formula, a new one can be established based on then-prevailing market conditions for aluminum or nickel, or the purchaser may purchase power under the applicable IP rate. Rate adjustments include a Preschedule Change Charge, Reactive Power Charge, and Unauthorized Increase.

5. Nonfirm Energy Rate (NF–96)

The proposed Nonfirm Energy (NF–96) rate schedule replaces the NF–95 rate. The proposed NF–96 rate schedule is available for purchases of nonfirm energy inside and outside the Pacific Northwest for resale to consumers, direct consumption, and resale under Western Systems Power Pool agreements. The proposed NF–96 rate schedule includes four rate components: a flexible Standard rate; a flexible Market Expansion rate; a flexible Incremental rate; and a fixed Contract rate. Adjustments include a Guaranteed Delivery, Preschedule Charge, and Reactive Power Charges. The NF Rate Cap continues to apply to all sales under the proposed NF–96 rate schedule. The NF Rate Cap defines the maximum nonfirm energy price for general application. The level of the NF Rate Cap is based on a formula tied to BPA's Average System Cost and California fuel costs.

6. Reserve Power Rate (RP–96)

The proposed Reserve Power (RP–96) rate schedule replaces the RP–95 rate schedule. The proposed RP rate is available in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied; when BPA determines no other rate schedule is applicable; or to serve a purchaser's firm power load when BPA does not have a power sales contract in force with such a purchaser, and BPA determines that this rate should be applied. The RP–96 rate consists of a demand charge, transmission charges, and seasonally and diurnally differentiated energy charges. Adjustments include a Reactive Power Charge.

7. Power Shortage Rate (PS–96)

The proposed Power Shortage (PS–96) rate schedule is available for sales under the Share-the-Shortage agreement or when BPA arranges for purchased energy at the request of a Northwest customer. BPA is not obligated to make Shortage Power available or to broker power under the proposed PS–96 rate schedule unless specified by contract. The proposed PS rate contains two rate components: a flexible Power Rate not to exceed 100 mills/kWh; and a flexible Brokering Rate not to exceed 1 mill/kWh. Adjustments include the Energy Return Surcharge, Deviation Adjustment, and Reactive Power and Unauthorized Increase Charges.

8. Firm Power and Services Rate (FPS–96)

The proposed Firm Power Products and Services (FPS–96) rate schedule will be available for the purchase of Firm Power and certain unbundled products including supplemental control area services, shaping and load factoring services, and resource support services. Firm power products and services that may be marketed by BPA under the proposed FPS–96 rate schedule are intended to be priced so that BPA has the flexibility to provide purchasers with customized products and services that are not available under other rate schedules. The proposed FPS–96 rate contains fixed and negotiable rates for Firm Power. The rates for products and services other than firm power may be negotiated between BPA and the purchaser. The proposed FPS–96 rate schedule supersedes the SP–93 and CE–95 rates.

9. Ancillary Products and Services Rate (APS–96)

The proposed Ancillary Products and Services (APS–96) rate schedule will be available for the ancillary services that are necessary to support the firm or nonfirm delivery of power that uses FCRTS facilities. The following ancillary services may be purchased under the proposed APS–96 rate: control area reserves for resources; control area reserves for interruptible purchases; load regulation; transmission losses; and scheduling and dispatch. The proposed APS–96 rate also will be available for ancillary services of a similar nature that FERC may order BPA to provide pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k).

C. Wholesale Power Rate Schedules

These schedules and GRSPs shall be applicable to BPA's power sales contracts, as appropriate, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. In addition, as stated in the availability section of each schedule, certain of the rates will be effective for extended periods of time. The GRSPs are an integral part of each rate schedule.

Schedule PF–96.2

Priority Firm Power

Section I. Availability

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest for a 2-year period, October 1, 1996, through September 30, 1998. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers for direct consumption. This schedule is available for all PF power purchases not subscribed at the PF–96.5 rate.

Rates in this schedule are applicable to purchases under requirements sales contracts effective on or before September 30, 1996 (hereinafter termed the ''*1981*'' contracts, although some are actually dated ''1984'' or later), and under contracts that may be effective on or after October 1, 1996 (''*1996*'' contracts). Customers that purchase under 1981 contracts may buy either firm power or capacity without energy under this rate schedule. Customers that purchase under 1996 contracts may buy only firm power. These and other products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs). Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

This rate schedule is also available to utilities participating in the residential and small farm exchange under section 5(c) of the Northwest Power Act pursuant to their Residential Purchase and Sale Agreement. All Priority Firm Power made available to utilities participating in the section 5(c) exchange shall be purchased under Section E of this rate schedule.

This rate schedule supersedes Schedule PF–95, which went into effect on October 1, 1995. Sales under the PF–96.2 rate schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for each PF product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified in separate sections of the rate schedule. The rates for each customer designation are identical except for Section E; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains five subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to Metered Requirements customers who purchase under a ''1981'' power sales contract.

Section II.B Applies to Full Requirements customers who purchase under a ''1996'' power sales contract.

Section II.C Applies to Computed Requirements customers who purchase under a ''1981'' power sales contract.

Section II.D Applies to Partial Requirements customers who purchase under a ''1996'' power sales contract.

Section II.E Applies to customers who purchase under a Residential Purchase and Sale Agreement (RPSA).

A. PF Rates for Metered Requirements Customers who Purchase Under a ''1981'' Power Sales Contract

Metered Requirements customers purchasing power under a ''1981'' power sales contract are required to buy Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. Priority Firm Power

1.1. Rates

1.1.1 Demand Charge

Applicable months	Rate
All months of the year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 2-year power only.

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

For purchasers of a combination of 2-year and 5-year power.

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.2. HLH Billing Energy

For purchasers of 2-year power only.

Purchaser's HLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

Purchaser's HLH Measured Energy minus the Purchaser's 5-year HLH Billing Energy.

1.2.3. LLH Billing Energy

For purchasers of 2-year power only.

Purchaser's LLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power

Purchaser's LLH Measured Energy minus the Purchaser's 5-year LLH Billing Energy.

2. Full Load Shaping

2.1. Rate

0.30 mills/kWh multiplied by the Utility Factor.

2.2. Billing Factor

For purchasers of 2-year power only.
Purchaser's total HLH and LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load shaping under the PF–96.2 rate schedule.

3. Load Regulation

3.1. Rate
0.25 mills/kWh multiplied by the Utility Factor.
3.2. Billing Factor
For purchasers of 2-year power only.
Purchaser's total HLH and LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load regulation under the PF–96.2 rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Low Density Discount	II.I.
Reactive Power Charge	II.N.
Transitional Service	II.P.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost contributions	II.B.
Utility factor	II.R.

B. PF Rates for Full Requirements Customers who Purchase Under a ''1996'' Power Sales Contract

Full Requirements Purchasers purchasing power under a ''1996'' power sales contract are required to buy Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 2-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.2. HLH Billing Energy

For purchasers of 2-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's HLH Measured Energy *minus* the Purchaser's 5-year HLH Billing Energy.

1.2.3. LLH Billing Energy

For purchasers of 2-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's LLH Measured Energy *minus* the Purchaser's 5-year LLH Billing Energy.

2. Full Load Shaping

2.1 Rate

0.30 mills/kWh.

2.2 Billing Factor

For purchasers of 2-year power only.
Purchaser's Retail Load minus the Purchaser's Industrial Exemption, if any.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load shaping under the PF–96.2 rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For purchasers of 2-year power only.
0.25 mills/kWh multiplied by Purchaser's Retail Load.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load regulation under the PF–96.2 rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation surcharge	II.A.
Deviation adjustment	II.D.
Industrial exemption/curtailment	II.H.
Low density discount	II.I.
Reactive power charge	II.N.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost contributions	II.B.

C. PF Rates for Computed Requirements Customers who Purchase Under a ''1981'' Power Sales Contract

Actual Computed Requirements Purchasers purchasing power under a ''1981'' power sales contract are required to buy Load Shaping and Network Integration Transmission service at the Network Integration (NT) rate. Planned and Contracted Computed Requirements Purchasers are not allowed to buy Load Shaping. Load Regulation is required if the customer is in BPA's load control area, regardless of whether the customer is purchasing on the basis of actual, planned, or contracted computed requirements. Planned and Contracted Computed Requirements customers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load *minus* the Purchaser's 5-year Billing Demand.

1.2.1.2 Without Load Shaping

For purchasers of 2-year power only.
Purchaser's Computed Peak Requirement.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's Computed Peak Requirement *minus* the Purchaser's 5-year Billing Demand.

1.2.2. Billing Energy

1.2.2.1 For Purchasers of 2-Year Power Only

For Energy Delivered September–March

The HLH Billing Energy is the Purchaser's HLH Measured Energy.
The LLH Billing Energy is:
a. 76 percent of the Purchaser's Measured Energy, *plus* 24 percent of the Purchaser's Computed Energy Maximum, *minus*
b. The Purchaser's HLH Measured Energy.

For Energy Delivered April–August

The HLH Billing Energy is the Purchaser's HLH Measured Energy.
The LLH Billing Energy is:
a. 63 percent of the Purchaser's Measured Energy, plus 37 percent of the Purchaser's Computed Energy Maximum, minus
b. The Purchaser's HLH Measured Energy.

1.2.2.2 For Purchasers of a Combination of 2-Year and 5-Year Power

The HLH Billing Energy is the Purchaser's HLH Computed Energy Maximum minus the Purchaser's 5-year HLH Billing Energy.
The LLH Billing Energy is the Purchaser's LLH Computed Energy Maximum minus the Purchaser's 5-year LLH Billing Energy.

2. Firm Capacity Without Energy

2.1. Rate

Applicable months	Rate
September–December	$1.11/kW-mo.
January–March	1.15/kW-mo.
April	0.82/kW-mo.
May–June	1.17/kW-mo.
July	1.23/kW-mo.
August	1.31/kW-mo.

2.2. Billing Factors

Purchaser's Computed Peak Requirement associated with the purchase of Firm Capacity Without Energy.

3. Full Load Shaping

3.1. Rate

0.30 mills/kwh multiplied by the Utility Factor.

3.2. Billing Factor

For purchasers of 2-year power only.
Purchaser's total HLH and LLH Billing Energy.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load shaping under the PF–96.2 rate schedule.

4. Load Regulation

4.1. Rate

0.25 mills/kWh multiplied by the Utility Factor.

4.2. Billing Factor

For purchasers of 2-year power only.
Purchaser's total HLH and LLH Billing Energy.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for load regulation under the PF–96.2 rate schedule.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Energy Return Surcharge	II.F.
Low Density Discount	II.I.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

6.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

D. PF Rates for Partial Requirements Customers Who Purchase Under A "1996" Power Sales Contract

Partial Requirements customers purchasing power under a 1996 power sales contract may purchase Load Shaping. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation. Partial Requirements customers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH Rate
September–December ..	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.1.1 Without Load Shaping

Purchaser's 2-year Demand Subscription.

1.2.2. HLH Billing Energy

1.2.2.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's HLH Measured Energy minus the Purchaser's 5-year HLH Billing Energy.

1.2.2.2 Without Load Shaping

Purchaser's 2-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

1.2.3.1 WITH Load Shaping

For purchasers of 2-year power only.

Purchaser's LLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

Purchaser's LLH Measured Energy minus the Purchaser's 5-year LLH Billing Energy.

1.2.3.2 Without Load Shaping

Purchaser's 2-year LLH Energy Subscription.

2. Full Load Shaping

2.1 Rate

0.30 mills/kWh.

2.2 Billing Factor

For purchasers of 2-year power only.

Purchaser's Retail Load minus the Purchaser's Industrial Exemption, if any.

For purchasers of a combination of 2-year and 5-year power.

There is no charge for load shaping under the PF–96.2 rate schedule.

3. Load Regulation

3.1 Rate and Billing Factor

For purchasers of 2-year power only.

0.25 mills/kWh multiplied by Purchaser's Retail Load.

For purchasers of a combination of 2-year and 5-year power.

There is no charge for load regulation under the PF–96.2 rate schedule.

4. Partial Load Shaping

4.1 Rate

$3.05/MWhr-hr.

4.2 Billing Factor

For purchasers of 2-year power only.

MWhr-hr amount of Partial Load Shaping Subscribed for the month.

For purchasers of a combination of 2-year and 5-year power.

There is no charge for partial load shaping under the PF–96.2 rate schedule.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Low Density Discount	II.I.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

6.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

E. PF Rates for Customers Who Purchase Under a Residential Purchase and Sale Agreement (RPSA)

The rate for RPSA customers includes Load Shaping and Load Regulation. RPSA customers are required to purchase transmission service under the Network Integration (NT) rate.

1. Rates

1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.2 Energy Charge

Applicable months	Rate
September–December	31.95
January–March	33.14
April	29.72
May–June	19.59
July	22.88
August	28.93

2. Billing Factors

2.1. Billing Demand

The Billing Demand shall be the demand calculated by applying the load factor, determined as specified in the RPSA, to the Billing Energy for each billing period.

2.2. Billing Energy

The Billing Energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's RPSA.

3. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

4. Adjustments, Charges, and Special Rate Provisions

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

Rate adjustment	Section
Conservation Surcharge	II.A.
Low Density Discount	II.I.

Schedule PF–96.5

Priority Firm Power

Section I. Availability

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest for a 5-year period, October 1, 1996, through September 30, 2001. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers for direct consumption. At their election, public body, cooperative, and Federal agency customers may purchase all or any designated portion of their power under this rate schedule as an alternative to purchasing power under the PF–96.2 rate schedule. Customers making such an election shall agree to purchase the designated amount of power exclusively from BPA for 5 years. Such election shall be a one-time irrevocable election and, as to the amount of power so designated, shall constitute a waiver of all rights to purchase power under any other power rate schedule for the 5-year period. The election process is described in section II.E. of the GRSPs.

Rates in this schedule are available for purchases under requirements sales contracts effective on or before September 30, 1996 (hereinafter termed the ''*1981*'' contracts, although some are actually dated ''1984'' or later), and under contracts that may be effective on or after October 1, 1996 (''*1996*'' contracts). Customers electing to purchase power under this rate schedule and continuing to receive service pursuant to their 1981 power sales contract further waive any rights under that contract to modify their Firm Resources Exhibit in such a manner that reduces or interferes with their ability to purchase power for loads dedicated for service under this rate schedule. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

Sales under the PF–96.5 rate schedule are subject to BPA's General Rate Schedule Provisions (GRSPs). Products available under this rate schedule are defined in the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for Each PF Product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified below. The rates for each customer designation are identical; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains five subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to Metered Requirements customers who purchase under a "1981" power sales contract.

Section II.B Applies to customers who elect to purchase on a composite rate basis.

Section II.C Applies to Full Requirements customers who purchase under a "1996" power sales contract and not on a composite rate basis.

Section II.D Applies to Computed Requirements customers who purchase under a "1981" power sales contracts.

Section II.E Applies to Partial Requirements customers who purchase under a "1996" power sales contracts.

A. PF Rates for Metered Requirements Customers who Purchase Under a "1981" Power Sales Contract

Metered Requirements customers purchasing power under a "1981" power sales contract are required to buy Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. Priority Firm Power

1.1. Rates

1.1.1 Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 5-year power only.

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

For purchasers of a combination of 2-year and 5-year power.

The lower of: Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

For purchasers of 5-year power only.

Purchaser's HLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

The lower of: Purchaser's HLH Measured Energy or Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

For purchasers of 5-year power only.

Purchaser's LLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

The lower of: Purchaser's LLH Measured Energy or Purchaser's 5-year LLH Energy Subscription.

2. Full Load Shaping

2.1. Rate

0.30 mills/kWh multiplied by the Utility Factor.

2.2. Billing Factor

Purchaser's total HLH and LLH Measured Energy.

3. Load Regulation

3.1. Rate

0.25 mills/kWh multiplied by the Utility Factor.

3.2. Billing Factor

Purchaser's total HLH and LLH Measured Energy.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Low Density Discount	II.I.
Phase-In Mitigation	II.L.
Reactive Power Charge	II.N.
Transitional Service	II.P.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

B. PF Rates for Customers who Elect to Purchase Power on a Composite Rate Basis

Only customers whose average annual retail loads during the 1996 rate period, as forecasted by BPA, are 25 average annual MW or less are eligible to purchase at this rate. The composite rate charge includes the PF–96.5 charges for demand, energy, Load Shaping, and Load Regulation. Purchasers at the composite rate also must purchase Network Integration Transmission service at the Network Integration (NT) rate.

1. Rate

Applicable months	Daily period	Rate (mills/kWh)
All Months of the Year	All hours	23.54

2. Billing Factor

Purchaser's Measured Energy.

3. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

4. Adjustments, Charges, and Special Rate Provisions

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

4.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Low Density Discount	II.I.
Phase-In Mitigation	II.L.
Reactive Power Charge	II.N.

4.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

C. PF Rates for Full Requirements Customers who Purchase Under a ''1996'' Power Sales Contract and not on a Composite Rate Basis

This customer category includes all Full Requirements customers whose forecasted loads exceed 25 aMW and those Full Requirements customers with forecasted loads of 25 aMW or less who decide not to purchase on a composite rate basis. Full Requirements Purchasers purchasing power under a —1996— power sales contract are required to buy Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September-December	22.20	19.64
January-March	23.02	20.28
April	20.65	19.46
May-June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 5-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

For purchasers of 5-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's HLH Measured Energy or Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

For purchasers of 5-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's LLH Measured Energy or Purchaser's 5-year LLH Energy Subscription.

2. Full Load Shaping

2.1. Rate

0.30 mills/kWh.

2.2 Billing Factor

Purchaser's Retail Load minus the Purchaser's Industrial Exemption, if any.

3. Load Regulation

3.1. Rate and Billing Factor

0.25 mills/kWh multiplied by Purchaser's Retail Load.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial.	
Exemption/Curtailment	II.H.
Low Density Discount	II.I.
Phase-In Mitigation	II.L.
Reactive Power Charge	II.N.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

D. PF Rates for Computed Requirements Customers Who Purchase Under a ''1981'' Power Sales Contract

Actual Computed Requirements Purchasers purchasing power under a ''1981'' power sales contract are required to buy Load Shaping and Network Integration Transmission service at the Network Integration (NT) rate. Planned and Contracted Computed Requirements Purchasers are not allowed to buy Load Shaping. Load Regulation is required if the customer is in BPA's load control area, regardless of whether the customer is purchasing on the basis of actual, planned, or contracted computed requirements. Planned and Contracted Computed Requirements purchasers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September-December	22.20	19.64
January-March	23.02	20.28
April	20.65	19.46
May-June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 5-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or Purchaser's 5-year Demand Subscription.

1.2.1.2 Without Load Shaping

For purchasers of 5-year power only.
Purchaser's 5-year Computed Peak Requirement.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's Computed Peak Requirement or Purchaser's 5-year Demand Subscription.

1.2.2. Billing Energy

1.2.2.1 For purchasers of 5-year power only

For Energy Delivered September-March

The HLH Billing Energy is the Purchaser's HLH Measured Energy.
The LLH Billing Energy is:
a. 76 percent of the Purchaser's Measured Energy, plus 24 percent of the Purchaser's Computed Energy Maximum, minus
b. The Purchaser's HLH Measured Energy

For Energy Delivered April-August

The HLH Billing Energy is the Purchaser's HLH Measured Energy.
The LLH Billing Energy is:
a. 63 percent of the Purchaser's Measured Energy, plus 37 percent of the

Purchaser's Computed Energy Maximum, minus

b. The Purchaser's HLH Measured Energy

1.2.2.2 For purchasers of a combination of 2-year and 5-year power

The HLH Billing Energy is the lower of:

Purchaser's HLH Computed Energy Maximum or

Purchaser's 5-year HLH Energy Subscription.

The LLH Billing Energy is the lower of:

Purchaser's LLH Computed Energy Maximum or Purchaser's 5-year LLH Energy Subscription.

2. Full Load Shaping

2.1. Rate

0.30 mills/kWh multiplied by the Utility Factor.

2.2. Billing Factor

Purchaser's total HLH and LLH Billing Energy.

3. Load Regulation

3.1. Rate

0.25 mills/kWh multiplied by the Utility Factor.

3.2. Billing Factor

Purchaser's total HLH and LLH Billing Energy.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Energy Return Surcharge	II.F.
Low Density Discount	II.I.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

E. PF Rates for Partial Requirements Customers who Purchase Under a "1996" Power Sales Contract

Partial Requirements customers purchasing power under a 1996 power sales contract may purchase Load Shaping. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation. Partial Requirements customers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Priority Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.20	19.64
January–March	23.02	20.28
April	20.65	19.46
May–June	13.61	10.78
July	15.90	12.79
August	20.10	16.63

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 5-year power only.

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

For purchasers of a combination of 2-year and 5-year power

The lower of: Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or Purchaser's 5-year Demand Subscription.

1.2.1.1 Without Load Shaping

Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

1.2.2.1 With Load Shaping

For purchasers of 5-year power only.

Purchaser's HLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

The lower of: Purchaser's HLH Measured Energy or Purchaser's 5-year HLH Energy Subscription.

1.2.2.2 Without Load Shaping

Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

1.2.3.1 With Load Shaping

For purchasers of 5-year power only.

Purchaser's LLH Measured Energy.

For purchasers of a combination of 2-year and 5-year power.

The lower of: Purchaser's LLH Measured Energy or Purchaser's 5-year LLH Energy Subscription.

1.2.3.2 Without Load Shaping

Purchaser's 5-year LLH Energy Subscription.

2. Full Load Shaping

2.1 Rate

0.30 mills/kWh.

2.2 Billing Factor

Purchaser's Retail Load minus the Purchaser's Industrial Exemption, if any.

3. Load Regulation

3.1 Rate and Billing Factor

0.25 mills/kWh multiplied by Purchaser's Retail Load.

4. Partial Load Shaping

4.1 Rate

$3.05/MWhr-hr.

4.2 Billing Factor

MWhr-hr amount of Partial Load Shaping Subscribed for the month.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Low Density Discount	II.I.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

6.2. Special Rate Provisions

Special Rate Provisions	Section
Cost Contributions	II.B.

Schedule NR–96.2

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 for a 2-year period, October 1, 1996, through September 30, 1998. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers. 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. Any power purchased by a customer to serve its New Large Single Load(s) must be purchased under either this rate schedule or under the NR–96.5 rate schedule.

Rates in this schedule are applicable to purchases under requirements sales contracts effective on or before September 30, 1996 (hereinafter termed the ''1981'' contracts, although some are actually dated ''1984'' or later), and under contracts that may be effective on or after October 1, 1996 (''1996'' contracts). Customers purchasing power under ''1981'' contracts may buy either firm power or capacity without energy under this rate schedule. Customers purchasing power under ''1996'' contracts may buy only firm power. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs). Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

This schedule supersedes Schedule NR–95, which went into effect on October 1, 1995. Sales under this schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for Each NR Product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified below. The rates for each customer designation are identical; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains four subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to public agency Metered Requirements customers who purchase under ''1981'' power sales contracts and serve new large single loads.

Section II.B Applies to Full Requirements customers who purchase under ''1996'' power sales contracts.

Section II.C Applies to Computed Requirements customers who purchase under ''1981'' power sales contracts.

Section II.D Applies to Partial Requirements customers who purchase under ''1996'' power sales contracts.

A. NR Rates for Metered Requirements Customers Who Purchase Under ''1981'' Power Sales Contracts and Serve New Large Single Loads

Metered Requirements customers purchasing power under a ''1981'' power sales contract serving a New Large Single Load (NLSL) are required to buy New Resource Firm Power (as needed for that NLSL), Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH Rate	LLH Rate
September–December ..	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

Purchaser's Measured Demand.

1.2.2. HLH Billing Energy

Purchaser's HLH Measured Energy.

1.2.3. LLH Billing Energy

Purchaser's LLH Measured Energy.

2. Full Load Shaping

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate

Rate

0.30 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.25 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate Adjustment	Section
Conservation Surcharge	II.A.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Transitional Service	II.P.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

B. NR Rates For Full Requirements Customers Who Purchase Under ''1996'' Power Sales Contracts

Full Requirements Purchasers purchasing power under a ''1996'' power sales contract are required to buy

Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/ kW-mo.

1.1.2. Energy Charge

Applicable months	HLH Rate	LLH rate
September—December	36.61	32.39
January—March	37.97	33.45
April	34.05	32.09
May—June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

Purchaser's Measured Demand.

1.2.2. HLH Billing Energy

Purchaser's HLH Measured Energy.

1.2.3. LLH Billing Energy

Purchaser's LLH Measured Energy.

2. Full Load Shaping

2.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.30 mills/kWh multiplied by Retail Load minus Industrial Exemption, if any.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.25 mills/kWh multiplied by Retail Load.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

C. NR Rates for Computed Requirements Customers who Purchase Under ''1981'' Power Sales Contracts

Actual Computed Requirements Purchasers purchasing power under a ''1981'' power sales contract are required to buy Load Shaping and Network Integration Transmission service at the Network Integration (NT) rate. Planned and Contracted Computed Requirements Purchasers are not allowed to buy Load Shaping, and must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-To-Point (PTP) rate. Load Regulation is required if the customer is in BPA's load control area.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand With Load Shaping

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

Without Load Shaping

Purchaser's Computed Peak Requirement.

1.2.2. Billing Energy

1.2.2.1 For Energy Delivered September–March

The HLH Billing Energy is the Purchaser's HLH Measured Energy.

The LLH Billing Energy is:

a. 55 percent of the Purchaser's Measured Energy, plus 45 percent of the Purchaser's Computed Energy Maximum, minus

b. The Purchaser's HLH Measured Energy

1.2.2.2 For Energy Delivered April–August

The HLH Billing Energy is the Purchaser's Measured Energy.

The LLH Billing Energy is:

a. 43 percent of the Purchaser's Measured Energy, plus 57 percent of the Purchaser's Computed Energy Maximum, minus

b. The Purchaser's HLH Measured Energy

2. Firm Capacity Without Energy

2.1. Rate

Applicable months	Rate
September–December	$1.47/kW-mo.
January–March	$1.54/kW-mo.
April	$0.98/kW-mo.
May–June	$1.57/kW-mo.
July	$1.67/kW-mo.
August	$1.80/kW-mo.

2.2. Billing Factor

Purchaser's Computed Peak Requirement associated with the purchase of Firm Capacity Without Energy.

3. Full Load Shaping

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.30 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

4. Load Regulation

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.25 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustments	Section
Conservation Surcharge	II.A.
Energy Return Surcharge	II.F.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Transitional Service	II.P.
Unauthorized Increase Charge	II.Q.

6.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

D. NR Rates for Partial Requirements Customers who Purchase Under ''1996'' Power Sales Contracts

Partial Requirements customers purchasing power under a ''1996'' power sales contract may purchase Load Shaping and must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation.

1. New Resource Firm Power

1.1. Rates

1.1.1 Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

With Load Shaping: Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

Without Load Shaping: Purchaser's Demand Subscription.

1.2.2. HLH Billing Energy

With Load Shaping: Purchaser's HLH Measured Energy.

Without Load Shaping:

Purchaser's HLH Energy Subscription.

1.2.3. LLH Billing Energy

With Load Shaping:

Purchaser's LLH Measured Energy.

Without Load Shaping:

Purchaser's LLH Energy Subscription.

2. Full Load Shaping

2.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.30 mills/kWh multiplied by Retail Load minus Industrial Exemption, if any.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.25 mills/kWh multiplied by Retail Load.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates .

There is no charge for Load Regulation under the NR rate schedule.

4. Partial Load Shaping

4.1 Rate

$3.05 per MWhr-hr.

4.2 Billing Factor

MWhr-hr amount of Partial Load Shaping Subscribed for the month.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

6.2. Special Rate Provisions

Special rate provision	Section
Cost Contributions	II.B.

Schedule NR–96.5—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 for a 5-year period, October 1, 1996, through September 30, 2001. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers. At their election, IOUs may purchase all or any designated portion of their power under this rate schedule as an alternative to purchasing power under the NR–96.2 rate schedule. IOU customers making such an election shall agree to purchase the designated amount of power exclusively from BPA for 5 years. 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. Any power purchased by a customer to serve its New Large Single Load(s) must be purchased under either this rate schedule or under the NR–96.2 rate schedule. Public body, cooperative, or Federal agency customers electing to be served under this rate schedule shall agree to purchase power for service to the designated consumer NLSL facilities exclusively from BPA for 5 years. Such election by IOUs or preference customers shall be a one-time irrevocable election and, as to the amount of power so designated, shall constitute a waiver of all rights to purchase power under any other power rate schedule for the 5-year period. The election process is described in section II.E. of the GRSPs.

Rates in this schedule are available for purchases under requirements sales contracts effective on or before September 30, 1996 (hereinafter termed the ''1981'' contracts, although some are actually dated ''1984'' or later), and under contracts that may be effective on or after October 1, 1996 (''*1996*'' contracts). Customers electing to purchase power under this rate schedule and continuing to receive service pursuant to their 1981 power sales contract further waive any rights under that contract to modify their Firm Resources Exhibit in such a manner that reduces or interferes with their ability to purchase the amount of power dedicated for service under this rate schedule. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

Sales under this schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for Each NR Product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified below. The rates for each customer designation are identical; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains five subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to public agency Metered Requirements customers who purchase under ''1981'' power sales contracts and serve new large single loads.

Section II.B Applies to Full Requirements customers who purchase under ''1996'' power sales contracts.

Section II.C Applies to Computed Requirements customers who purchase under ''1981'' power sales contracts.

Section II.D Applies to Partial Requirements customers who purchase under ''1996'' power sales contracts.

A. NR Rates for Metered Requirements Customers who Purchase Under ''1981'' Power Sales Contracts and Serve New Large Single Loads

Metered Requirements customers purchasing power under a ''1981'' power sales contract serving a New Large Single Load (NLSL) are required to buy New Resource Firm Power (as needed for that NLSL), Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

Purchaser's Measured Demand.

1.2.2. HLH Billing Energy

Purchaser's HLH Measured Energy.

1.2.3. LLH Billing Energy

Purchaser's LLH Measured Energy.

2. Full Load Shaping

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.30 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.25 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Phase-In Mitigation	II.L.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Transitional Service	II.P.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

B. NR Rates for Full Requirements Customers Who Purchase Under ''1196'' Power Sales Contracts

Full Requirements Purchasers purchasing power under a ''1996'' power sales contract are required to buy Load Shaping, Load Regulation, and Network Integration Transmission service at the Network Integration (NT) rate.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

Purchaser's Measured Demand.

1.2.2. HLH Billing Energy

Purchaser's HLH Measured Energy.

1.2.3. LLH Billing Energy

Purchaser's LLH Measured Energy.

2. Full Load Shaping

2.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.30 mills/kWh multiplied by Retail Load minus Industrial Exemption, if any.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.25 mills/kWh multiplied by Retail Load.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment .	II.H.
Phase-In Mitigation	II.L.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

C. NR Rates for Computed Requirements Customers Who Purchase Under ''1981'' Power Sales Contracts

Actual Computed Requirements Purchasers purchasing power under a ''1981'' power sales contract are required to buy New Resource Firm Power (as needed), Load Shaping, and Network Integration Transmission service at the Network Integration (NT) rate. Planned and Contracted Computed Requirements Purchasers are not allowed to buy Load Shaping, and must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate. Load Regulation is required if the customer is in BPA's load control area.

1. New Resource Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

With Load Shaping:

Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

Without Load Shaping:

Purchaser's Computed Peak Requirement.

1.2.2. Billing Energy

1.2.2.1 For Energy Delivered September–March

The HLH Billing Energy is the Purchaser's HLH Measured Energy.

The LLH Billing Energy is:

a. 55 percent of the Purchaser's Measured Energy, plus 45 percent of the Purchaser's Computed Energy Maximum, minus

b. The Purchaser's HLH Measured Energy.

1.2.2.2 For Energy Delivered April–August

The HLH Billing Energy is the Purchaser's Measured Energy.

The LLH Billing Energy is:

a. 43 percent of the Purchaser's Measured Energy, plus 57 percent of the Purchaser's Computed Energy Maximum, minus

b. The Purchaser's HLH Measured Energy.

2. Full Load Shaping

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.30 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

Rate

0.25 mills/kWh multiplied by the Utility Factor.

Billing Factor

Purchaser's HLH and LLH Measured Energy.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Energy Return Surcharge	II.F.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

Rate adjustment	Section
Transitional Service	II.P.
Unauthorized Increase Charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.
Utility Factor	II.R.

D. NR Rates for Partial Requirements Customers who Purchase Under ''1996'' Power Sales Contracts

Partial Requirements customers purchasing power under a ''1996'' power sales contract may purchase New Resource Firm Power (as needed) and Load Shaping, and must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation.

1. New Resource Firm Power

1.1. Rates

1.1.1 Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2. Billing Factors

1.2.1. Billing Demand

With Load Shaping:
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
Without Load Shaping:
Purchaser's Demand Subscription.

1.2.2. HLH Billing Energy

With Load Shaping:
Purchaser's HLH Measured Energy.
Without Load Shaping:
Purchaser's HLH Energy Subscription.

1.2.3. LLH Billing Energy

With Load Shaping:
Purchaser's LLH Measured Energy.
Without Load Shaping:
Purchaser's LLH Energy Subscription.

2. Full Load Shaping

2.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.30 mills/kWh multiplied by Retail Load minus Industrial Exemption, if any.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Shaping under the NR rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For Purchasers whose Requirements Service is Provided Exclusively under the NR Rate.

0.25 mills/kWh multiplied by Retail Load minus Industrial Exemption, if any.

For Purchasers whose Requirements Service is Provided under Both the PF and NR Rates.

There is no charge for Load Regulation under the NR rate schedule.

4. Partial Load Shaping

4.1 Rate

$3.05/MWhr-hr.

4.2 Billing Factor

MWhr-hr amount of Partial Load Shaping Subscribed for the month.

5. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

6. Adjustments, Charges, and Special Rate Provisions

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

6.1. Rate Adjustments

Rate adjustment	Section
Conservation Surcharge	II.A.
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

6.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

Schedule IP–96.2—Industrial Firm Power Rate

Section I. Availability

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their industrial operations for a 2-year period, October 1, 1996, through September 30, 1998. If a DSI requests that BPA serve a portion of its load under another rate schedule and if BPA agrees, the IP–96.2 rate shall apply to only that portion of its load that is not served under the other schedule.

Both DSIs that purchase power under power sales contracts that were effective on or before September 30, 1996 (hereinafter termed the ''1981'' contracts), and DSIs that purchase power under new contracts (hereinafter termed the ''1996'' contracts) are eligible to purchase under this rate schedule. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs). Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

This rate schedule supersedes Schedule IP–95, which went into effect on October 1, 1995. Sales under the IP–96.2 rate schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments shall be due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for Each IP Product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified in separate sections of the rate schedule. The rates for each customer designation are identical; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Under the power sales contracts, the DSIs provide operating reserves and stability reserves. The credit for these reserves is reflected in the level of the applicable energy charges specified in this rate schedule. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains three subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to DSI purchasers who purchase under ''1981'' power sales contracts.

Section II.B Applies to Full Requirements DSI purchasers who purchase under ''1996'' contracts.
Section II.C Applies to Partial Requirements DSI purchasers who purchase under ''1996'' contracts.

A. IP Rates for DSI Purchasers who Purchase Under ''1981'' Power Sales Contracts

DSI Purchasers purchasing power under a ''1981'' power sales contract are required to buy Load Regulation and either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September—December	22.29	19.72
January—March	23.11	20.36
April	20.73	19.54
May—June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 2-year power only.
Purchaser's BPA Operating Level that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's BPA Operating Level that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.2. HLH Billing Energy

For purchasers of 2-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's HLH Measured Energy minus the Purchaser's 5-year HLH Billing Energy.

1.2.3. LLH Billing Energy

For purchasers of 2-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's LLH Measured Energy minus the Purchaser's 5-year LLH Billing Energy.

2. Load Regulation

2.1. Rate and Billing Factor

For purchasers of 2-year power only.
0.25 mills/kWh multiplied by Purchaser's Retail Load.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for Load Regulation under the IP–96.2 rate schedule.

3. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

4. Adjustments, Charges, and Special Rate Provisions

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

4.1. Rate Adjustments

Rate adjustment	Section
Curtailment Charge	II.C.
Operating Reserves Adjustment	II.K.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Transitional Service	II.P.
Unauthorized Increase Charge	II.Q.

4.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

B. IP Rates for Full Requirements DSI Purchasers who Purchase Under ''1996'' Power Sales Contracts

Full Requirements customers purchasing power under a ''1996'' power sales contract are required to buy Load Shaping, Load Regulation, and either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September—December	22.29	19.72
January—March	23.11	20.36
April	20.73	19.54
May–June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 2-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.2. HLH Billing Energy

For purchasers of 2-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power
Purchaser's HLH Measured Energy minus the Purchaser's 5-year HLH Billing Energy.

1.2.3. LLH Billing Energy

For purchasers of 2-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's LLH Measured Energy minus the Purchaser's 5-year LLH Billing Energy.

2. DSI Load Shaping

2.1. Rate

$187/aMW.

2.2 Billing Factor

For purchasers of 2-year power only.
Purchaser's Calculated Energy Capacity minus the Purchaser's Industrial Exemption, if any.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for Load Shaping under the IP–96.2 rate schedule.

3. Load Regulation

3.1. Rate and Billing Factor

For purchasers of 2-year power only.
0.25 mills/kWh multiplied by Purchaser's Retail Load.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for Load Regulation under the IP–96.2 rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the

Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Industrial Exemption/Curtailment	II.H.
Operating Reserves Adjustment	II.K.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

C. IP Rates for Partial Requirements DSI Purchasers who Purchase Under ''1996'' Power Sales Contracts

Partial Requirements customers purchasing power under a ''1996'' power sales contract may purchase Load Shaping. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation. Partial Requirements customers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.29	19.72
January–March	23.11	20.36
April	20.73	19.54
May–June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load minus the Purchaser's 5-year Billing Demand.

1.2.1.1 Without Load Shaping

Purchaser's 2-year Demand Subscription.

1.2.2. HLH Billing Energy

1.2.2.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's HLH Measured Energy minus the Purchaser's 5-year HLH Billing Energy.

1.2.2.2 Without Load Shaping

Purchaser's 2-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

1.2.3.1 With Load Shaping

For purchasers of 2-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
Purchaser's LLH Measured Energy minus the Purchaser's 5-year LLH Billing Energy.

1.2.3.2 Without Load Shaping

Purchaser's 2-year LLH Energy Subscription.

2. DSI Load Shaping

2.1 Rate

$187/aMW.

2.2 Billing Factor

For purchasers of 2-year power only.
Purchaser's Calculated Energy Capacity minus the Purchaser's Industrial Exemption, if any.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for Load Shaping under the IP–96.2 rate schedule.

3. Load Regulation

3.1 Rate and Billing Factor

For purchasers of 2-year power only.
0.25 mills/kWh multiplied by Purchaser's Retail Load.
For purchasers of a combination of 2-year and 5-year power.
There is no charge for Load Regulation under the IP–96.2 rate schedule.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Deviation Adjustment	II.D.
Industrial Exemption/Curtailment	II.H.
Operating Reserves Adjustment	II.K.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

Schedule IP–96.5—Industrial Firm Power Rate

Section I. Availability

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their industrial operations for a 5-year period, October 1, 1996, through September 30, 2001. At their election, customers may purchase all or any designated portion of their power under this rate schedule as an alternative to purchasing power under the IP–96.2 rate schedule. Customers making such an election shall agree to purchase the designated amount of power exclusively from BPA for 5 years. Such election shall be a one-time irrevocable election and, as to the amount of power so designated, shall constitute a waiver of all rights to purchase power under any other power rate schedule for the 5-year period. The election process is described in section II.E. of the GRSPs.

Both DSIs that purchase power under power sales contracts that were effective on or before September 30, 1996 (hereinafter termed the ''1981'' contracts), and DSIs that purchase power under new contracts (hereinafter termed the ''1996'' contracts) are eligible to purchase under this rate schedule. Customers electing to purchase power under this rate schedule and continuing to receive service pursuant to their ''1981'' power sales contract further waive any rights to terminate service under that contract upon 12 months' notice. This waiver does not, however, preclude customers from signing ''1996'' power sales contracts for an amount of power equal to or greater than the amount designated to be purchased under the 5-year rate. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs). Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges.

Sales under the IP–96.5 rate schedule are subject to BPA's GRSPs. For sales under this rate schedule, bills shall be rendered and payments shall be due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments for Each IP Product

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified in separate sections of the rate schedule. The rates for each customer designation are identical; the billing factors, however, vary according to the customer designation. Applicable adjustments and special rate provisions are listed for each customer designation. Under the power sales contracts, the DSIs provide operating reserves and stability reserves. The credit for these reserves is reflected in the level of the applicable energy charges specified in this rate schedule. Network Integration transmission service at the Network Integration (NT) rate or Point-to-Point transmission service at the Point-to-Point (PTP) rate is required for purchases under this rate schedule.

This rate schedule contains three subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A Applies to DSI purchasers who purchase under ''1981'' power sales contracts.

Section II.B Applies to Full Requirements DSI purchasers who purchase under ''1996'' contracts.

Section II.C Applies to Partial Requirements DSI purchasers who purchase under ''1996'' contracts.

A. IP Rates for DSI Purchasers who Purchase Under ''1981'' Power Sales Contracts

DSI Purchasers purchasing power under a ''1981'' power sales contract are required to buy Load Regulation and either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.29	19.72
January–March	23.11	20.36
April	20.73	19.54
May–June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 5-year power only.
Purchaser's BPA Operating Level that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's BPA Operating Level that occurs during the hour of the Monthly Transmission Peak Load or
Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

For purchasers of 5-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's HLH Measured Energy or
Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

For purchasers of 5-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's LLH Measured Energy or
Purchaser's 5-year LLH Energy Subscription.

2. Load Regulation

2.1. Rate and Billing Factor

0.25 mills/kWh multiplied by Purchaser's Retail Load.

3. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

4. Adjustments, Charges, and Special Rate Provisions

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

4.1. Rate Adjustments

Rate adjustment	Section
Curtailment Charge	II.C.
Operating Reserves Adjustment ..	II.K.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Transitional Service	II.P.
Unauthorized Increase Charge	II.Q.

4.2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

B. IP Rates for Full Requirements DSI Purchasers who Purchase Under ''1996'' Power Sales Contracts

Full Requirements customers purchasing power under a ''1996'' power sales contract are required to buy Load Shaping, Load Regulation, and either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.29	19.72
January–March	23.11	20.36
April	20.73	19.54
May–June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

For purchasers of 5-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or
Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

For purchasers of 5-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's HLH Measured Energy or
Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

For purchasers of 5-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's LLH Measured Energy or
Purchaser's 5-year LLH Energy Subscription.

2. DSI Load Shaping

2.1. Rate

$187/aMW.

2.2 Billing Factor

Purchaser's Calculated Energy Capacity minus the Purchaser's Industrial Exemption, if any.

3. Load Regulation

3.1. Rate and Billing Factor

0.25 mills/kWh multiplied by Purchaser's Retail Load.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Page
Industrial Exemption/Curtailment	II.H.
Operating Reserves Adjustment	II.K.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Page
Cost Contributions	II.B.

C. IP Rates for Partial Requirements DSI Purchasers who Purchase Under "1996" Power Sales Contracts

Partial Requirements customers purchasing power under a "1996" power sales contract may purchase Load Shaping. All customers in BPA's load control area are required to buy Load Regulation, and customers outside of BPA's load control area may not buy Load Regulation. Partial Requirements customers must elect either Network Integration Transmission service at the Network Integration (NT) rate or Point-to-Point Transmission service at the Point-to-Point (PTP) rate.

1. Industrial Firm Power

1.1. Rates

1.1.1. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	22.29	19.72
January–March	23.11	20.36
April	20.73	19.54
May–June	13.67	10.82
July	15.96	12.84
August	20.18	16.69

1.2. Billing Factors

1.2.1. Billing Demand

1.2.1.1 With Load Shaping

For purchasers of 5-year power only.
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's Measured Demand that occurs during the hour of the Monthly Transmission Peak Load or Purchaser's 5-year Demand Subscription.

1.2.1.1 Without Load Shaping

Purchaser's 5-year Demand Subscription.

1.2.2. HLH Billing Energy

1.2.2.1 With Load Shaping

For purchasers of 5-year power only.
Purchaser's HLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's HLH Measured Energy or
Purchaser's 5-year HLH Energy Subscription.

1.2.2.2 Without Load Shaping

Purchaser's 5-year HLH Energy Subscription.

1.2.3. LLH Billing Energy

1.2.3.1 With Load Shaping

For purchasers of 5-year power only.
Purchaser's LLH Measured Energy.
For purchasers of a combination of 2-year and 5-year power.
The lower of:
Purchaser's LLH Measured Energy or
Purchaser's 5-year LLH Energy Subscription.

1.2.3.2 Without Load Shaping

Purchaser's 5-year LLH Energy Subscription.

2. DSI Load Shaping

2.1 Rate

$187/aMW.

2.2 Billing Factor

Purchaser's Calculated Energy Capacity minus the Purchaser's Industrial Exemption, if any.

3. Load Regulation

3.1 Rate and Billing Factor

0.25 mills/kWh multiplied by Purchaser's Retail Load.

4. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

5. Adjustments, Charges, and Special Rate Provisions

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

5.1. Rate Adjustments

Rate adjustment	Section
Deviation adjustment	II.D.
Industrial exemption/curtailment	II.H.
Operating reserves adjustment	II.K.
Preschedule change charge	II.M.
Reactive power charge	II.N.
Unauthorized increase charge	II.Q.

5.2. Special Rate Provisions

Special rate provisions	Section
Cost contributions	II.B.

Schedule VI–96—Variable Industrial Power Rate

Section I. Availability

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their aluminum and nickel smelting operations). Only DSIs that purchase power under the 1996 Contract) and that have signed a new Variable Industrial Rate Contract are eligible to purchase under this rate schedule. BPA is not obligated to sell power under this rate schedule. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

A customer electing to purchase power under this rate schedule must first elect service to its entire load under either the IP–96.2 rate schedule or the IP–96.5 rate schedule. The purchaser may not purchase power under both rate schedules pursuant to the election process described in section II.E. of the GRSPs. Any variable rate established pursuant to this rate schedule will apply to the purchaser's entire load.

At the expiration of the variable rate formula, a new one can be established, or the customer may purchase power under the applicable IP rate. However, the total term of all variable rate formulas for any DSI customer shall not be longer than 2 years under the IP–96.2 rate schedule and five years under the IP–96.5 rate schedule.

This rate schedule supersedes Schedule VI–95, which went into effect on October 1, 1995. Sales under the VI–96 rate schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments shall be due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments

A. Variable Industrial Firm Power

1. Rates

The variable rate formula will be based on the IP rate under which the customer has elected service. The Demand Charge for the variable rate will be the same as the Demand Charge in the applicable IP rate. The Base Energy Charge will be the average annual charge that results from applying the Energy Charges and the Load Regulation charge from the applicable IP rate to the customer's forecasted load. For customers that have elected service under the IP–96.2 rate schedule, upon the expiration of such schedule the Base Energy Charge shall be such annual average charge from any subsequent Industrial Firm Power Rate Schedule under which such customer elects service.

The monthly Energy Charge varies with the price of aluminum, in the case of customers engaged in primary aluminum reduction, and with the price of nickel, in the case of customers engaged in primary nickel reduction. Individual rate formulas will be established for each customer. Each rate formula shall be such that, at the time BPA enters into a Variable Industrial Rate Contract with the individual customer incorporating such formula, BPA has the ability to hedge the aluminum or nickel price risk inherent in such rate formula, at zero cost to BPA, by entering into transactions with one or more substantial financial institutions.

(''Zero cost to BPA'' means that either a) BPA will incur no cost to hedge the price risk of the variable rate, or b) BPA will recover the sum it pays to hedge the price risk of the variable rate from the applicable customer, either as a lump sum paid at the time BPA and the customer enter into the Variable Rate Contract, or over a time period no longer than the term of the variable rate formula incorporated in such contract. In the event that such sum is recovered over time, it shall bear interest at the rate payable on the Bonneville Fund in the United States Treasury at the time BPA and the customer enter into the Variable Rate Contract.)

Individual rate formulas may be established for any period from one to two years, in the case of customers purchasing power under the IP–96.2 rate schedule, and for any period from one to five years, in the case of customers purchasing power under the IP–96.5 rate schedule. At the expiration of any rate formula, a new rate formula for that customer may be established pursuant to the guidelines stated in this section, or the customer may purchase power under the applicable Industrial Firm Power rate schedule. However, the total term of all variable rate formulas for any single DSI purchaser shall not be longer than two years in the case of customers that have elected service under the IP–96.2 rate schedule, and five years in the case of customers that have elected service under the IP–96.5 rate schedule.

The monthly Energy Charge shall be based on the monthly billing aluminum or nickel price. The monthly billing aluminum or nickel price shall be the average price of aluminum or nickel, in dollars per metric ton, on the London Metal Exchange (LME) during the calendar month immediately preceding the billing month. The average price during the month shall equal the average of all official LME daily cash settlement prices during such month rounded to the nearest dollar. BPA and each customer may agree to base the monthly energy charge on the average price of aluminum or nickel during a month other than the immediately preceding month.

In the case of variable industrial rate formulas that contain pivot prices, the monthly Energy Charge shall be the Base Energy Charge when the monthly billing aluminum or nickel price is between the Lower Pivot Aluminum or Nickel Price and the Upper Pivot Aluminum or Nickel Price inclusive. In the case of variable industrial rate formulas that do not contain pivot prices, the monthly Energy Charge shall be the Base Energy Charge when the monthly billing aluminum or nickel price equals the price established in the customer's Variable Industrial Rate Contract at which the Base Energy Charge applies.

The Lower Pivot Aluminum or Nickel Price is the aluminum or nickel price established in an individual customer's Variable Industrial Rate Contract such that the monthly energy charge decreases when the monthly billing aluminum or nickel price is below such price.

The Upper Pivot Aluminum or Nickel Price is the aluminum or nickel price established in an individual customer's Variable Industrial Rate Contract such that the monthly energy charge increases when the monthly billing aluminum or nickel price is above such price.

2. Billing Factors

2.1. Billing Demand

Purchaser's Demand Subscription.

2.2. Billing Energy

Purchaser's Energy Subscription.

B. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

C. Adjustments, Charges, and Special Rate Provisions

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

1. Rate Adjustments

Rate adjustment	Section
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

2. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

Schedule NF–96—Nonfirm Energy 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. BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's ''1981'' or ''1996'' Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. For purchases under this rate schedule, transmission service over FCRTS facilities shall be available at the applicable transmission rate schedule.

This rate schedule supersedes schedule NF–95, which went into effect on October 1, 1995. Sales under the NF–96 rate schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments

The average cost of nonfirm energy is 20.92 mills per kilowatt-hour. The NF–96 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap calculated in accordance with the methodology specified in the Adjustments, Charges, and Special Rate Provisions section of this document.

A. Rates for Nonfirm Energy

1. Standard Rate

The Standard rate is any offered rate not to exceed 25.12 mills per kilowatt-hour.

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 per kilowatt-hour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatt-hour) 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 20.92 mills per kilowatt-hour.

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 GRSPs. The applicable sections are identified for each adjustment.

1. Rate Adjustments

Rate adjustment	Section
Guaranteed Delivery Charge	II.G.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.

2. Special Rate Provisions

Special rate provision	Section
Cost Contributions	II.B.
NF Rate Cap	II.J.

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:

1. is available for all purchases of nonfirm energy; and

2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the ''1981'' utility power sales contract.

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 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 per kilowatt-hour.

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 per kilowatt-hour.

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 per kilowatt-hour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.00 mills per kilowatt-hour.

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 if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.00 mills per kilowatt-hour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below purchaser's qualifying decremental cost minus 4.00 mills per kilowatt-hour.

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) less 2.00 mills per kilowatt-hour.

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 the 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 shall 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 that agreement.

F. End-User Rate

BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall 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.

Schedule RP–96—Reserve Power Rate

Section I. Availability

This schedule is available for the purchase of power:

A. In cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;

B. For which BPA determines no other rate schedule is applicable; or

C. To serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP–95, which went into effect on October 1, 1995. Sales under this schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

A. Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

B. Energy Charge

Applicable months	HLH rate	LLH rate
September–December	24.3 mills/kWh	21.5 mills/kWh.
January–March	25.2 mills/kWh	22.2 mills/kWh.
April	22.6 mills/kWh	21.3 mills/kWh.
May–June	14.9 mills/kWh	11.8 mills/kWh.
July	17.4 mills/kWh	14.0 mills/kWh.
August	22.0 mills/k	18.2 mills/kWh.

Section III. Billing Factors

A. Billing Demand

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise, the billing demand shall be the Measured Demand that occurs during the hour of the Monthly Transmission Peak Load.

B. Billing Energy

The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise, the Billing Energy for such purchasers shall be the HLH and LLH Measured Energy.

Section IV. Adjustments, Charges, and Special Rate Provisions

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

A. Rate Adjustments

Rate adjustment	Section
Reactive Power Charge	II.N.

B. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

Schedule PS–96—Power Shortage Rate Schedule

Section I. Availability

This schedule is available inside the Pacific Northwest for the purchase of Shortage Power by signatories to the Share-the-Shortage Agreement, or a similar substitute agreement. Any transactions entered into by BPA pursuant to a Share-the-Shortage Agreement shall be subject to the terms and conditions specified in that agreement. The PS–96 rate does not incorporate the Agreement, but the Agreement controls if there is any conflict between the PS–96 rate and the Agreement. The PS–96 rate shall not be available for transactions with a party who triggers the Share-the-Shortage Agreement if BPA elects to meet its required service obligations under the agreement by entering into an alternative agreement.

This rate schedule is also available inside the Pacific Northwest when BPA arranges for the purchase of energy at the request of, and for the account of, a customer pursuant to a Share-the-Shortage Agreement.

BPA is not obligated either to make Shortage Power available or to broker power under this rate schedule unless specified by contract.

This schedule supersedes schedule PS–95, which went into effect on October 1, 1995. Sales under the PS–96 rate schedule are subject to BPA's General Rate Schedule Provisions (GRSPs), and BPA's Billing Procedures.

Section II. Rates

A. Power Rate

The power rate is any offered rate not to exceed the lesser of:

1. 100.00 mills per kilowatt-hour; or

2. the maximum rate specified in the Share-the Shortage Agreement. The offered rate may be specified as an energy charge only or as demand and energy charges.

B. Brokering Rate

The brokering rate may be up to 1.00 mill per kilowatt-hour for services provided when BPA arranges for energy purchases for a customer from a seller other than BPA.

Section III. Billing Factors

A. Power Purchases

The billing factors shall be the Contract Demand and Contract Energy, unless otherwise specified in the agreement initiating the Share-the-Shortage sales transaction.

B. Brokering Services

When BPA arranges for energy purchases at the request of a customer, the purchaser shall be billed for such services based on the total number of kilowatt-hours purchased.

The charge for power brokering only applies to the service provided by BPA of finding purchased power for a customer from a seller other than BPA. BPA may agree to provide other services in addition to finding purchased power, but these services shall be billed separately at charges specified in the appropriate rate schedule(s) or agreement(s). Such services may include, but are not limited to, wheeling and load shaping.

Section IV. Transmission

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

Section V. Adjustments, Charges, and Special Rate Provisions

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

A. Rate adjustments

Rate Adjustment	Section
Deviation Adjustment	II.D.
Reactive Power Charge	II.N.

B. Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

Schedule FPS–96—Firm Power Products and Services

Section I. Availability

This rate schedule is available for the purchase of Firm Power, Control Area Services that are not defined as ancillary services, and Shaping Services for use inside and outside the Pacific Northwest during the period beginning October 1, 1996, and ending September 30, 2005.

Products and services available under this rate schedule are described in the ''Definitions'' section of BPA's General Rate Schedule Provisions (GRSPs). BPA is not obligated to enter into agreements to sell products and services under this rate schedule or make power or energy available under this rate schedule if such power or energy would displace sales under the PF–96.2, PF–96.5, NR–96.2, NR–96.5, IP–96.2, IP–96.5, or VI–96 rate schedules or their successors. Sales under the FPS–96 rate schedule are subject to BPA's GRSPs. For purchases under this rate schedule, transmission service over FCRTS facilities shall be available under the applicable transmission rate schedule, and ancillary services shall be available under the Ancillary Products and Services (APS) rate schedule.

This rate schedule supersedes the Surplus Firm Power (SP–93) and Emergency Capacity (CE–95) rate schedules. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates, Billing Factors, and Adjustments

This section of the rate schedule is organized as follows:

Section II.A. Rates, billing factors, and adjustments for Firm Power.

Section II.B. Rates, billing factors, and adjustments for Supplemental Control Area Services.

Section II.C. Rates, billing factors, and adjustments for Shaping Services.

A. Firm Power

1. Rates

1.1 Contract Rate

1.1.1 Demand Charge

Applicable months	Rate
All Months of the Year	$0.56/kW-mo.

1.1.2 Energy Charge

Applicable months	HLH rate	LLH rate
September–December	36.61	32.39
January–March	37.97	33.45
April	34.05	32.09
May–June	22.45	17.78
July	26.22	21.09
August	33.15	27.42

1.2 Flexible Rate

Demand and/or energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the Purchaser.

1.3 Reservation Charge

The reservation charge for reserving the right to change future delivery of firm energy and/or capacity may be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. Billing Factors

2.1 Billing Demand

The Billing Demand for Firm Power shall be the Contract Demand unless otherwise agreed by BPA and the Purchaser.

2.2 Billing Energy

The Billing Energy for Firm Power shall be the Contract Energy unless otherwise agreed by BPA and the Purchaser.

2.3 Billing Factor for Reserved Firm Power

The billing factor for reserved Firm Power shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

3. Adjustments

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

3.1 Rate Adjustments

Rate adjustment	Section
Energy Return Surcharge	II.F.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

3.2 Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

B. Control Area Services That Are Not Ancillary Services

1. Rates

The rate(s) shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

2. Billing Factors

The billing factor(s) for control area services shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

3. Adjustments

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

3.1 Rate Adjustments

Rate adjustment	Section
Energy Return Surcharge	II.F.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	I.Q.

3.2 Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

C. Shaping Services

1. Rate

1.1 Rate for Shaping and Load Factoring Service

The rate shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

1.2 Reservation Charge

The reservation charge for reserving the right to take future delivery of shaping services shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

2. Billing Factor

2.1 Billing Factor for Shaping Services

The Billing Factor(s) shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

2.2 Billing Factors for Reservation of the Right to Purchase Shaping Services

The Billing Factor(s) shall be as specified by BPA or as mutually agreed by BPA and the Purchaser.

3. Adjustments

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

3.1 Rate Adjustments

Rate adjustment	Section
Energy Return Surcharge	II.F.
Preschedule Change Charge	II.M.
Reactive Power Charge	II.N.
Unauthorized Increase Charge	II.Q.

3.2 Special Rate Provisions

Special rate provisions	Section
Cost Contributions	II.B.

APS–96—Ancillary Products and Services

Section I. Availability

This rate schedule is available for ancillary services necessary to support the firm or non-firm delivery of power from resources to loads using the Federal Columbia River Transmission System (FCRTS) facilities. The ancillary products and services available under this rate schedule are: Scheduling and Dispatching; Control Area Reserves for Resources; Control Area Reserves for Interruptible Purchases; Load Regulation; and Transmission Losses. These services are defined in the ‘‘Definitions’’ section of BPA's General Rate Schedule Provisions (GRSPs). This schedule is also available for ancillary services of a similar nature as BPA may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k).

To the extent that FERC allows transmitting utilities subject to the Federal Power Act to sell ancillary services at rates other than stated rates, the provisions providing for a flexible rate for the ancillary products or services provided in this schedule may apply.

Sales under this schedule are made subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rates and Billing Factors

This section of the rate schedule is organized as follows:

Section II.A Identifies the rates and billing factors for Scheduling and Dispatching.

Section II.B Identifies the rates and billing factors for Control Area Reserves for Resources.

Section II.C Identifies the rates and billing factors for Control Area Reserves for Interruptible Purchases.

Section II.D Identifies the rates and billing factors for Load Regulation.

Section II.E Identifies the rates and billing factors for Transmission Losses.

A. Scheduling and Dispatching

1. Rates

1.1 Rate for Scheduling and Dispatching

The rate for scheduling and dispatching service shall be $71 per Preschedule.

1.2 Rate for Preschedule Change

The rate for Preschedule Changes shall be $33 per change.

2. Billing Factors

2.1 Billing Factor for Scheduling and Dispatch

The billing factor shall be the sum of Preschedules made for each of the Purchaser's scheduling accounts per billing month.

2.2 Billing Factor for Preschedule Change

The billing factor shall be the sum of Preschedule Changes made for each of the Purchaser's scheduling accounts per billing month.

B. Control Area Reserves for Resources

1. Rates

The rates below for Control Area Reserves For Resources apply to all hydro-electric and non-hydroelectric generating resources located in BPA—s control area. The rates below do not apply to such resources with generating capacity of less than one MW.

1.2 Rate for Control Area Reserves for Hydroelectric Resources

1.2.1 Stated Rate

The rate shall be $0.35 per kilowatt-month of billing demand.

1.2.2 Flexible Rate

The rate shall be specified by BPA for such service.

1.3 Rate for Control Area Reserves for Non-Hydroelectric Resources

1.3.1 Stated Rate

The rate shall be $0.50 per kilowatt-month of billing demand.

1.3.2 Flexible Rate

The rate shall be specified by BPA for such service.

2. Billing Factors

2.1 Billing Demand

If the Purchaser's resource(s), regardless of resource type, have appropriate metering equipment, the billing demand shall be determined as specified in section 2.1.1 below. Otherwise, for the purchaser's hydroelectric resource(s) the billing demand shall be determined in accordance with section 2.1.2, and for the purchaser(s) thermal and any other non-hydroelectric resource(s) the billing demand shall be determined in accordance with section 2.1.3.

2.1.1 Billing Demand for Metered Resources

For service applicable to the Purchaser's resource(s) regardless of type, having appropriate metering equipment, the billing demand shall be the average metered energy for each resource for the billing month.

2.1.2 Billing Demand for Hydroelectric Resources

For service applicable to the Purchaser's hydroelectric resource(s) the billing demand shall be the total Resource Capability, as specified in section B.2.1.4, for the Purchaser's hydroelectric resource(s), multiplied by a capacity factor of 0.60.

2.1.3 Billing Demand for Non-Hydroelectric Resources

For service applicable to the Purchaser's thermal resource(s) and any other non-hydro-electric resource(s), the billing demand shall be the total Resource Capability for the Purchaser's thermal resource(s) and any other non-hydroelectric resource(s), multiplied by a capacity factor of 0.90.

2.1.4 Resource Capability

For service under 1981 power sales contracts, the Resource Capability, expressed in kilowatts, shall be equal to the Assured Peaking Capability of the Purchaser's resource(s). For 1996 contracts and all other agreements, the Resource Capacity shall be the Monthly Resource Peaking Capability as specified in the Agreement.

C. Control Area Reserves for Interruptible Purchases

1. Rates

1.1 Rate for Control Area Reserves for Interruptible Purchases

1.1.1 Stated Rate

The rate shall be 4.00 mills per kilowatt-hour.

1.1.2 Flexible Rate

The rate shall be specified by BPA for such service.

2. Billing Factor

The billing factor shall be the sum of scheduled amounts of Interruptible Energy per billing month.

D. Load Regulation

1. Rate

1.1 Stated Rate

The rate shall be 0.25 mills per kilowatt-hour of billing energy.

1.2 Flexible Rate

The rate shall be specified by BPA for such service.

2. Billing Factor

The billing factor for load regulation shall be the measured monthly kilowatt-hours of the purchaser's Retail Load.

E. Transmission Losses

1. RATE

1.1 Stated Rate

For agreements that provide the option of purchasing transmission losses, the rate shall be 29.34 mills per kilowatt-hour.

1.2 Flexible Rate

The rate shall be specified by BPA for such service.

2. Billing Factor

The Billing Factor shall be the amount of losses for the billing month calculated as specified in the applicable Agreement.

D. Summary of Transmission Rate Schedules

FPT–96—Formula Power Transmission Rate

FPT–96.3—Formula Power Transmission Rate

IR–96—Integration of Resources Rate

NT–96.2—Network Integration Transmission Rate

NT–96.5—Network Integration Transmission Rate

PTP–96.2—Point-to-Point Firm Transmission Rate

PTP–96.5—Point-to-Point Firm Transmission Rate

ET–96—Energy Transmission Rate

IS–96—Southern Intertie Transmission Rate

IN–96—Northern Intertie Transmission Rate

IE–96—Eastern Intertie Transmission Rate

MT–96—Market Transmission Rate

UFT–96—Use-of-Facilities Transmission Rate

AF–96—Advance Funding Rate

TGT–96—Townsend-Garrison Transmission Rate

A summary of the proposed 1996 Transmission Rate Schedules is provided below. Each of the rate schedules includes sections specifying the service available under the rate schedule, the rates for the products and services offered under the schedule, the billing factors, and other special provisions for rate adjustments, such as the discounts or penalties that apply to that rate schedule.

Three new transmission rates are proposed: the Network Integration Transmission rate; the Point-to-Point Transmission rate; and the Advance Funding rate. Nonfirm rates in the proposed Southern Intertie, Northern Intertie, Eastern Intertie, and Energy Transmission rate schedules are revised to allow for downward flexibility from the stated cost. A Reservation Fee for Transmission Capacity and a Reactive Power Charge are included in many of the transmission rate schedules. BPA also has provided for charging opportunity costs in the firm transmission rates for new requests for transmission capacity. The Ancillary Products and Services rate schedule which specifies the charges for ancillary services that may be required to use BPA's transmission system is included in BPA's wholesale power rate proposal.

1. Formula Power Transmission (FPT–96)

The FPT–96 rate is available for the firm wheeling of power on the network segment of the FCRTS. This rate includes a distance or mileage component for transmission lines and various transformation and terminal charges. The FPT rate form is designed to reflect a wheeling formula that is prescribed by contract provisions. The rate schedule provides for annual and seasonal service. Two FPT rate schedules are developed—one for rates that cannot be changed more frequently than once a year, and one for rates that cannot be changed more frequently than once every 3 years. Revised rates are proposed for both rate schedules.

2. Integration of Resources (IR–96)

The IR service is a flexible transmission service that may be used to integrate multiple resources and transmit non-Federal power to multiple points of delivery on the FCRTS Network facilities. The IR–96 rate is structured as a postage-stamp (independent of distance) rate. The proposed IR–96 rate schedule continues to include the Short-Distance Discount, an exception to the postage stamp rate design for contractually specified points of integration. The IR rate has traditionally included both demand and energy charges; BPA is proposing that the IR–96 rate be a demand-only rate.

3. Network Integration (NT–96)

Network Integration transmission service allows customers to serve their load located in the PNW region. The proposed NT–96 rate is designed to conform generally with the pricing provisions of the FERC NOPR Network Integration tariff. The proposed NT–96 rate includes a Network demand charge that is applied to a customer's total retail load occurring at the hour of the monthly BPA transmission system peak, with a credit for the utility's transmission facilities. For customers with 1981 contracts, the Network charge will be applied to power delivered under those contracts on the hour of the monthly BPA transmission peak and no credit is given for customer transmission facilities. The rate schedule also includes delivery charges for customers served over Utility or DSI Delivery facilities. The NT rate also provides for a charge or credit to compensate for redispatching of resources. The NT rate will apply to BPA full requirements customers; partial requirements customers may elect either Network Integration Transmission service using the NT rate or Point to Point Transmission service using the Point to Point rate (see below). Residential Purchase and Sale Agreement purchasers shall take service under the 2-year NT rate.

4. Point-to-Point (PTP–96)

Point-to-Point transmission service allows customers to serve their retail load and/or transactions with third parties and off-system sales over the Network. BPA also will apply this rate for sale to, and purchases for, its own customers which are not native load customers. The proposed PTP–96 rate is designed to conform generally with the pricing provisions of the FERC NOPR Point-to-Point tariff. The proposed PTP–96 rate includes a Network demand charge that is applied to the greater of: (1) the sum of the monthly Point of Integration Transmission Demands; or (2) the sum of the monthly Point of Delivery Transmission Demands. The PTP rate may apply to firm transmission service of 1 month or longer. The rate schedule also includes delivery charges for customers served over Utility or DSI Delivery facilities.

5. Energy Transmission (ET–96)

The ET rate applies to firm service of less than a month and to nonfirm service over FCRTS facilities excluding the Interties. The rate may be used for service taken under the Point-to-Point tariff. The firm rate is a take-or-pay energy charge. The nonfirm rate is specified as a cap with flexibility below that level.

6. Southern Intertie (IS–96), Northern Intertie (IN–96), and Eastern Intertie (IE–96)

The IS rate and IN rate are available for service over those respective facilities. The rates are structured similarly: a nonfirm energy-only rate; and a firm rate with separate demand and energy components. The nonfirm rates are specified as a cap with flexibility below those levels. The IE rate is available for nonfirm transmission on the Eastern Intertie and is structured as an energy-only rate with downward flexibility.

7. Market Transmission (MT–96)

BPA is continuing the MT rate unchanged, except for the addition of the Reactive Power Charge. This rate schedule was developed for use among Western Systems Power Pool (WSPP) participants and allows for flexible hourly, daily, weekly, and monthly charges.

8. Use of Facilities Transmission (UFT–96) and Townsend-Garrison Transmission (TGT–96)

The UFT–96 and TGT–96 rate schedules are formula rates that are being proposed unchanged from the current rates. The UFT rate recovers the annual cost of identified facilities over which specific wheeling transactions occur. The TGT rate is a contract rate that recovers the cost of the Montana (Eastern) Intertie.

9. Advance Funding (AF–96)

The proposed AF rate allows BPA to collect the capital and related costs of specified BPA-owned transmission facilities through advance payment. Such facilities could include interconnection and resource integration facilities, and upgrades or reinforcements to the FCRTS. Following commercial operation of the specified facilities, a true-up of estimated costs with actual costs would occur.

10. Reservation Fee for Transmission Capacity and Reactive Power Charge

The proposed Reservation Fee is included in the firm transmission rate schedules for application to customers who enter into a contract with BPA for new or increased firm transmission service on the FCRTS and want to postpone the commencement of such service while maintaining the availability of transmission capacity. Payment of the Reservation Fee for Transmission Capacity would allow a customer to postpone service for a year at a time for up to 5 years. This proposed Reservation Fee is modeled on the one in FERC's Point-to-Point tariff. The proposed Reactive Power Charge is included in BPA's transmission rate schedules as well as BPA's power rate schedules, and charges customers for their reactive power requirements by point of delivery and points of interconnection.

E. Transmission Rate Schedules

Schedule FPT–96.2—Formula Power Transmission Rate

Section I. Availability

This schedule supersedes schedule FPT–95.1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once a year. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The monthly charge shall be A or B.

A. Embedded Cost

1. Full-Year Service

The monthly charge per kilowatt of Billing Demand shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

a. Main Grid Charge: The Main Grid Charge per kilowatt of Billing Demand shall be the sum of one or more of the following component factors as specified in the agreement:

(1) Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0526 per mile.
(2) Main Grid Interconnection Terminal Factor: $0.36.
(3) Main Grid Terminal Factor: $0.59.
(4) Main Grid Miscellaneous Facilities Factor: $2.79.
b. Secondary System Charge The Secondary System Charge per kilowatt of Billing Demand shall be the sum of one or more of the following component factors as specified in the agreement:
(1) Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.3769 per mile.
(2) Secondary System Transformation Factor: $5.37.
(3) Secondary System Intermediate Terminal Factor: $1.70.
(4) Secondary System Interconnection Terminal Factor: $1.17.

2. Partial-Year Service

The monthly charge per kilowatt of Billing Demand shall be as specified in section II.A.1 for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:
a. During months for which service is specified, the monthly charge defined in section II.A.1, and
b. During other months, the monthly charge defined in section II.A.1 multiplied by 0.2.

B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.

Section III. Billing Factors

A. Embedded Cost

Unless otherwise stated in the agreement, the Billing Demand for the rates specified in section II.A. shall be the largest of:
1. The Transmission Demand;
2. The highest hourly Scheduled Demand for the month; or
3. The Ratchet Demand.

B. Opportunity Cost

Billing factors for the rate specified in section II.B. shall be specified in the agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support FPT transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

C. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Provisions.

D. Rates Applicable to FPT Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

Schedule FPT–96.3—Formula Power Transmission Rate

Section I. Availability

This schedule supersedes schedule FPT–95.3 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every three years. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The monthly charge shall be A or B.

A. Embedded Cost

1. Full-Year Service

The monthly charge per kilowatt of Billing Demand shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.
a. Main Grid Charge: The Main Grid Charge per kilowatt of Billing Demand shall be the sum of one or more of the following component factors as specified in the agreement:
(1) Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0526 per mile.
(2) Main Grid Interconnection Terminal Factor: $0.36.
(3) Main Grid Terminal Factor: $0.59.
(4) Main Grid Miscellaneous Facilities Factor: $2.79.
b. Secondary System Charge: The Secondary System Charge per kilowatt of Billing Demand shall be the sum of one or more of the following component factors as specified in the agreement:
(1) Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.3769 per mile.
(2) Secondary System Transformation Factor: $5.37.
(3) Secondary System Intermediate Terminal Factor: $1.70.
(4) Secondary System Interconnection Terminal Factor: $1.17.

2. Partial-Year Service

The monthly charge per kilowatt of Billing Demand shall be as specified in section II.A.1 for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:
a. During months for which service is specified, the monthly charge defined in section II.A.1, and
b. During other months, the monthly charge defined in section II.A.1 multiplied by 0.2.

B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.

Section III. Billing Factors

A. Embedded Cost

Unless otherwise stated in the agreement, the Billing Demand for the rates specified in section II.A. shall be the largest of:
1. The Transmission Demand;
2. The highest hourly Scheduled Demand for the month; or
3. The Ratchet Demand.

B. Opportunity Cost

Billing factors for the rate specified in section II.B. shall be specified in the agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support FPT transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

C. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

D. Rates Applicable to FPT Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

Schedule IR–96—Integration of Resources Rate

Section I. Availability

This schedule supersedes IR–95 and is available for transmission of non-Federal power for full-year firm transmission service and nonfirm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network facilities. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The monthly charge shall be A or B.

A. Embedded Cost

The monthly charge shall be:

1. $1.188 per kilowatt of Billing Demand; or

2. For Points of Integration (POI) specified in the Agreement as being short distance POIs, for which Main Grid and Secondary System facilities are used for a distance of less than 75 circuit miles, the following formula applies: [0.2 + (0.8 $\times$ transmission distance/75)] * $0.594 per kilowatt of billing demand.

Where the Billing Demand for a short distance POI is the demand level specified in the Agreement for such POI, and the transmission distance is the circuit miles between the POI for a generating resource of the customer and a designated Point of Delivery serving load of the customer. Short distance POIs are determined by BPA after considering factors in addition to transmission distance.

B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.

Section III. Billing Factors

To the extent that the agreement provides for the customer to be billed for transmission in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at the Energy Transmission rate, such transmission service shall not contribute to either the Billing Demand or the Billing Energy for the IR rate provided that the customer requests such treatment and BPA approves in accordance with the prescribed provisions in the agreement.

A. Embedded Cost

The Billing Demand shall be the largest of:

1. The Transmission Demand, or, if defined in the agreement, the Total Transmission Demand;

2. The highest hourly Scheduled Demand for the month; or

3. The Ratchet Demand.

B. Opportunity Cost

Billing factors shall be specified in the agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support IR transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

C. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

D. Rates Applicable to IR Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

Schedule NT–96.2 Network Integration Transmission Rate

Section I. Availability

This schedule is available to each customer that executes a Network Integration Service Agreement (Agreement) and does not elect the 5-year rate option. Such Agreement provides for delivery of Federal and non-Federal power to the customer's Network Load over Federal Columbia River Transmission System Network and Utility/DSI Delivery facilities. Terms and conditions of service are specified in the Network Integration Service Tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k). This schedule is available to utilities participating in the residential exchange under section 5(c) of the Northwest Power Act pursuant to their Residential Purchase and Sale Agreements (RPSA). Service under this schedule is not available for transmission of non-Federal power to customers taking service concurrently under the Integration of Resources rate or Formula Power Transmission rate. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The monthly charge shall be the sum of A and B.

A. Network Charge

$1.597 per kilowatt per month of Billing Demand.

B. Delivery Charges

1. Utility

For service over Utility Delivery facilities, the charge is $1.143 per kilowatt per month of Billing Demand.

2. DSI

For service over DSI Delivery facilities, the charge is $0.404 per kilowatt per month of Billing Demand.

C. Redispatch Credit/Cost

When BPA implements redispatch procedures pursuant to the Network Integration Service Tariff, the total cost impact of such procedures shall be shared among Network Integration customers based on the ratio of each customer's NT Network Charge Billing Demand to the sum of all NT Network Charge Billing Demands. Such Billing Demands shall be for the month in which the redispatch cost is incurred. Redispatch cost shall be charged on NT customers' monthly bills in a lump sum amount.

To the extent that the cost borne by the NT customer whose resource was redispatched is greater than such customer's cost share (as determined above), a credit shall be given on the affected NT customer's monthly bill. To the extent that the cost borne by the affected NT customer is less than such customer's cost responsibility, the difference shall be charged on the affected NT customer's monthly bill.

Section III. Billing Factors

A. Network Charge

1. Billing Demand

The monthly Billing Demand for the charge specified in section II.A. shall be the Customer's Load.

Where ''Customer's Load'' is the customer's Network Load measured during the hour of the Monthly Transmission Peak Load. For customers with 1981 Contracts, ''Customer's Load'' is the power taken under 1981 Contracts during the hour of the Monthly Transmission Peak Load. ''Monthly Transmission Peak Load'' is the monthly peak loading on the FCRTS for the billing month.

''Network Load'' is the designated load of a Transmission Customer including the entire load of all designated Member Systems. A Transmission Customer's Network Load shall not be reduced to reflect any portion of such load served by the output of any generating facilities owned, or generation purchased, by the Transmission Customer, its Member Systems, or other customers served by the Transmission Customer under the Network Integration Service Tariff.

The Network Load is the Transmission Customer's actual total system load, including distribution losses. No distinction is made between load that is served with BPA power and load that is served with power from other sources. To the extent the Transmission Customer is served with resources remote from their system, Network Load shall be measured at specified Points of Delivery.

2. Residential Exchange

For RPSA utilities, the Billing Demand shall be the demand calculated by applying the load factor, determined as specified in the RPSA, to the energy associated with the utility's residential load for each billing period. Residential load shall be determined in accordance with the provisions of the purchaser's RPSA.

3. Network Billing Demand Adjustment

The Network Charge Billing Demand determined under section III.A.1. shall be decreased by the power delivered under any BPA power sales contract, not including 1981 Contracts and 1996 Contracts, during the hour of the Monthly Transmission Peak Load. Adjustments shall be made for power delivered under contracts executed prior to October 1, 1996, that bundle the price for transmission with the price for power, or specify a transmission rate different than this NT Network rate.

B. Delivery Charge

The monthly billing demand for the charges specified in section II.B. shall be the Customer's Load that occurs during the hour of the Monthly Transmission Peak Load at the Points of Delivery specified in BPA's Segmentation Study as Utility Delivery or DSI Delivery facilities.

C. Adjustment for Metering

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the highest hourly peak demand during the billing month at the Point of Delivery multiplied by 0.76.

Section IV. Adjustments and Other Provisions

A. Customer Facilities Credit

Monthly bills for the Network Charge specified in section II.A. shall be reduced by a Customer Facilities Credit, if contractually specified. The Customer Facilities Credit is based on the annual cost of customer-owned transmission facilities which would be included in BPA's revenue requirement for the Network segment if BPA owned such customer facilities. The specification of which customer-owned transmission facilities shall be included in the Customer Facilities Credit shall be based on a determination of whether BPA would be responsible for providing such facilities, in accordance with BPA's Customer Service Policy, if the requesting party were a BPA full requirements power customer. The annual cost of the identified customer-owned transmission facilities shall be based on the customer's costs. The Customer Facilities Credit will be specified as a monthly amount in an exhibit to the contract. The Customer Facilities Credit is not available to Metered and Computed Requirements Customers.

B. Credit to NT Network Charge Bill

A credit shall be made to the monthly bill for Network Integration Transmission Service for Partial Requirements Customers who purchase transmission service under Integration of Resources (IR) or Formula Power Transmission (FPT) rate schedules. Such credit shall equal the portion of the monthly bill for IR or FPT service to the customer's Network Load.

C. Credit to Delivery Charges

A credit shall be made to the monthly bill for Network Integration Transmission Service for customers who pay for Utility Delivery or DSI Delivery facilities under the Use-of-Facilities (UFT) rate schedule. The credit shall equal the monthly UFT charges for such Delivery facilities.

D. Ancillary Services

Ancillary services that may be required to support NT transmission service are available under the APS rate schedule.

E. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

F. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Integration Transmission customer under an applicable rate schedule.

G. Rates Applicable to NT Service

The rates specified in section II are applicable to service over available transmission capacity. NT customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC-order granting final approval of this rate schedule for FERC ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

Schedule NT–96.5—Network Integration Transmission Rate

Section I. Availability

This schedule is available to each customer that executes a Network Integration Service Agreement (Agreement) and elects the 5-year rate option. Such Agreement provides for delivery of Federal and non-Federal power to the customer's Network Load over Federal Columbia River Transmission System Network and Utility/DSI Delivery facilities. Terms and conditions of service are specified in the Network Integration Service Tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k). Service under this schedule is not available for transmission of non-Federal power to customers taking service concurrently under the Integration of Resources rate or Formula Power Transmission rate. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The monthly charge shall be the sum of A and B.

A. Network Charge

$1.656 per kilowatt per month of Billing Demand.

B. Delivery Charges

1. Utility

For service over Utility Delivery facilities, the charge is $1.164 per kilowatt per month of Billing Demand.

2. DSI

For service over DSI Delivery facilities, the charge is $0.415 per kilowatt per month of Billing Demand.

C. Redispatch Credit/Cost

When BPA implements redispatch procedures pursuant to the Network Integration Service Tariff, the total cost impact of such procedures shall be shared among Network Integration customers based on the ratio of each customer's NT Network Charge Billing Demand to the sum of all NT Network Charge Billing Demands. Such Billing Demands shall be for the month in which the redispatch cost is incurred. Redispatch cost shall be charged on NT customers' monthly bills in a lump sum amount.

To the extent that the cost borne by the NT customer whose resource was redispatched is greater than such customer's cost share (as determined above), a credit shall be given on the affected NT customer's monthly bill. To the extent that the cost borne by the affected NT customer is less than such customer's cost responsibility, the difference shall be charged on the affected NT customer's monthly bill.

Section III. Billing Factors

A. Network Charge

1. Billing Demand

The monthly billing demand for the charge specified in section II.A. shall be the Customer's Load.

Where ''Customer's Load'' is the customer's Network Load measured during the hour of the Monthly Transmission Peak Load. For customers with 1981 Contracts, ''Customer's Load'' is the power taken under the 1981 Contracts during the hour of the Monthly Transmission Peak Load. ''Monthly Transmission Peak Load'' is the monthly peak loading on the FCRTS for the billing month.

''Network Load'' is the designated load of a Transmission Customer including the entire load of all designated Member Systems. A Transmission Customer's Network Load shall not be reduced to reflect any portion of such load served by the output of any generating facilities owned, or generation purchased, by the Transmission Customer, its Member Systems, or other customers served by the Transmission Customer under the Network Integration Service Tariff.

The Network Load is the Transmission Customer's actual total system load, including distribution losses. No distinction is made between load that is served with BPA power and load that is served with power from other sources. To the extent the Transmission Customer is served with resources remote from their system, Network Load shall be measured at specified Points of Delivery.

2. Network Billing Demand Adjustment

The Network Charge Billing Demand determined under section III.A.1. shall be decreased by the power delivered under any BPA power sales contract, not including 1981 Contracts and 1996 Contracts, during the hour of the Monthly Transmission Peak Load. Adjustments shall be made for power delivered under contracts executed prior to October 1, 1996, that bundle the price for transmission with the price for power, or specify a transmission rate different than this NT Network rate.

B. Delivery Charge

The monthly Billing Demand for the charges specified in section II.B. shall be the Customer's Load that occurs during the hour of the Monthly Transmission Peak Load at the Points of Delivery specified in BPA's Segmentation Study as Utility Delivery or DSI Delivery facilities.

C. Adjustment for Metering

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the highest hourly peak demand during the billing month at the Point of Delivery multiplied by 0.76.

Section IV. Adjustments and Other Provisions

A. Customer Facilities Credit

Monthly bills for the Network Charge specified in section II.A. shall be reduced by a Customer Facilities Credit, if contractually specified. The Customer Facilities Credit is based on the annual cost of customer-owned transmission facilities which would be included in BPA's revenue requirement for the Network segment if BPA owned such customer facilities. The specification of which customer-owned transmission facilities shall be included in the Customer Facilities Credit shall be based on a determination of whether BPA would be responsible for providing such facilities, in accordance with BPA's Customer Service Policy, if the requesting party were a BPA full requirements power customer. The annual cost of the identified customer-owned transmission facilities shall be based on the customer's costs. The Customer Facilities Credit will be specified as a monthly amount in an exhibit to the contract. The Customer Facilities Credit is not available to Metered and Computed Requirements Customers.

B. Credit to NT Network Charge Bill

A credit shall be made to the monthly bill for Network Integration Transmission Service for Partial Requirements customers who purchase transmission service under Integration of Resources (IR) or Formula Power Transmission (FPT) rate schedules. Such credit shall equal the portion of the monthly bill for IR or FPT service to the customer's Network Load.

C. Credit to Delivery Charges

A credit shall be made to the monthly bill for Network Integration Transmission Service for customers who pay for Utility Delivery or DSI Delivery facilities under the Use-of-Facilities (UFT) rate schedule. The credit shall equal the monthly UFT charges for such Delivery facilities.

D. Ancillary Services

Ancillary services that may be required to support NT transmission service are available under the APS rate schedule.

E. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section N of the General Rate Schedule Provisions.

F. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Integration Transmission customer under an applicable rate schedule.

G. Rates Applicable to NT Service

The rates specified in section II are applicable to service over available transmission capacity. NT customers that integrate new Network Resources, new Member Systems, or new Native Load Customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

Schedule PTP–96.2—Point-to-Point Transmission Rate

Section I. Availability

This schedule is available to each Customer that executes a Point-to-Point Transmission Service Agreement (Agreement) and does not elect the 5-year rate option. Such Agreement provides for firm transmission service for Federal and non-Federal power for one calendar month or longer and for nonfirm transmission service in amounts not to exceed the customer's total Transmission Demand over Federal Columbia River Transmission System (FCRTS) Network and Utility/DSI Delivery facilities. Terms and conditions of service are specified in the Point-to-Point Transmission Service Tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k). Service under this schedule for the transmission of non-Federal power is not available to customers taking service concurrently under the Integration of Resources rate or Formula Power Transmission rate. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

A. Network Charge

The charge shall be 1 or 2.

1. Embedded Cost

$1.315 per kilowatt per month of Billing Demand.

2. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.1.

B. Delivery Charge

1. Utility

For service over Utility Delivery facilities, the charge is $1.143 per kilowatt per month of Billing Demand.

2. DSI

For service over DSI Delivery facilities, the charge is $0.404 per kilowatt per month of Billing demand.

Section III. Billing Factors

The monthly Transmission Demands shall be contractually specified.

A. Network Charge

1. Embedded Cost

The monthly Billing Demand for the rate specified in section II.A.1. shall be the greater of:

a. the sum of the monthly Point of Integration Transmission Demands (including monthly peak subscriptions designated pursuant to 1996 Contracts and computed peak requirements pursuant to 1981 Contracts) that correspond to the current billing month, or

b. the sum of the monthly Point of Delivery Transmission Demands (including monthly peak subscriptions designated pursuant to 1996 Contracts and computed peak requirements pursuant to 1981 Contracts) that correspond to the current billing month.

2. Opportunity Cost

The billing factor for the rate in section II.A.2. shall be specified in the Agreement.

B. Delivery Charge

The monthly Billing Demand for the charges specified in section II.B. shall be the Measured Demand that occurs during the hour of the Monthly

Transmission Peak Load at the Points of Delivery specified in BPA's Segmentation Study as Utility Delivery or DSI Delivery facilities.

At those points of delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the highest hourly peak demand during the billing month at the Point of Delivery multiplied by 0.76.

Section IV. Other Provisions

A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

B. Ancillary Services

Ancillary services that may be required to support PTP transmission service are available under the APS rate schedule.

C. PTP Unauthorized Transmission Increase Charge

Customers who exceed their monthly Point of Integration (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the PTP Unauthorized Transmission Increase Charge.

1. Rate

$16.78 per kilowatt of Billing Demand.

2. Billing Factor

The Billing Demand shall be the number of kilowatts that exceeds the monthly Transmission Demand at any POI or POD, or exceeds the sum of monthly POI or POD Transmission Demands, on any hour.

D. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

E. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Point-to-Point Transmission customer under an applicable rate schedule.

F. Redispatch

When BPA determines that capacity constraints that may be relieved more economically through redispatching the system rather than by building new facilities or upgrading existing facilities to eliminate such constraints, the customer taking Point-to-Point Transmission Service shall be responsible for such costs to the extent consistent with FERC policy.

G. Rates Applicable to PTP Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

Schedule PTP–96.5—Point-to-Point Firm Transmission Rate

Section I. Availability

This schedule is available to each Customer that executes a Point-to-Point Transmission Service Agreement (Agreement) and elects the 5-year rate option. Such Agreement provides for firm transmission service for Federal and non-Federal power for one calendar month or longer and for nonfirm transmission service in amounts not to exceed the customer's total Transmission Demand over Federal Columbia River Transmission System (FCRTS) Network and Utility/DSI Delivery facilities. Terms and conditions of service are specified in the Point-to-Point Transmission Service Tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k). Service under this schedule for the transmission of non-Federal power is not available to customers taking service concurrently under the Integration of Resources rate or Formula Power Transmission rate. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

A. Network Charge

The charge shall be 1 or 2.

1. Embedded Cost

$1.386 per kilowatt per month of Billing Demand.

2. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A

B. Delivery Charge

1. Utility

For service over Utility Delivery facilities, the charge is $1.164 per kilowatt per month of Billing Demand.

2. DSI

For service over DSI Delivery facilities, the charge is $0.415 per kilowatt per month of Billing Demand.

Section III. Billing Factors

The monthly Transmission Demands shall be contractually specified.

A. Network Charge

1. Embedded Cost

The monthly Billing Demand for the rate specified in section II.A.1. shall be the greater of:

a. the sum of the monthly Point of Integration Transmission Demands (including monthly peak subscriptions designated pursuant to 1996 Contracts and computed peak requirements pursuant to 1981 Contracts) that correspond to the current billing month, or

b. the sum of the monthly Point of Delivery Transmission Demands (including monthly peak subscriptions designated pursuant to 1996 Contracts and computed peak requirements pursuant to 1981 Contracts) that correspond to the current billing month.

2. Opportunity Cost

The billing factor(s) for the rate in section II.A.2. shall be specified in the Agreement.

B. Delivery Charge

The monthly Billing Demand for the charges specified in section II.B. shall be the Measured Demand that occurs during the hour of the Monthly Transmission Peak Load at the Points of Delivery specified in BPA's Segmentation Study as Utility Delivery or DSI Delivery facilities.

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the highest hourly peak demand during the billing month at the Point of Delivery multiplied by 0.76.

Section IV. Other Provisions

A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

B. Ancillary Services

Ancillary services that may be required to support PTP transmission service are available under the APS rate schedule.

C. PTP Unauthorized Transmission Increase Charge

Customers who exceed their monthly Point of Integration (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the PTP Unauthorized Transmission Increase Charge.

1. Rate

$15.63 per kilowatt of Billing Demand.

2. Billing Factor

The Billing Demand shall be the number of kilowatts that exceeds the monthly Transmission Demand at any POI or POD, or exceeds the sum of monthly POI or POD Transmission Demands, on any hour.

D. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

E. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Point-to-Point Firm Transmission customer under an applicable rate schedule.

F. Redispatch

When BPA determines that capacity constraints may be relieved more economically through redispatching the system rather than by building new facilities or upgrading existing facilities to eliminate such constraints, the customer taking Point-to-Point Transmission Service shall be responsible for such costs to the extent consistent with FERC policy.

G. Rates Applicable to PTP Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

Schedule ET–96—Energy Transmission Rate

Section I. Availability

This schedule supersedes ET–95 and is available for transmission service between points within the Pacific Northwest using Federal Columbia River Transmission System (FCRTS) facilities excluding the Southern Intertie, Eastern Intertie, and Northern Intertie. This rate is available for transmission of Federal and non-Federal power for firm transmission service of less than one calendar month duration and for nonfirm transmission service. Terms and conditions of Energy Transmission service are specified in the Point-to-Point Service Tariff. This schedule is available for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The charge shall be A or B.

A. Firm

1. Embedded Cost

2.44 mills per kilowatt-hour.

2. Opportunity Cost

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.1.

B. Nonfirm

The charge shall not exceed 2.44 mills per kilowatt-hour.

Section III. Billing Factors

The Billing Energy for the charge specified in section II.A.1. shall be the Contract Energy.

The Billing Energy for the rate in section II.A.2. shall be specified in the agreement.

The Billing Energy for charges under section II.B. shall be the monthly sum of scheduled kilowatt-hours.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support ET transmission service are available under the APS rate schedule.

B. ET Unauthorized Transmission Increase Charge

Customers who exceed their Contract Energy at any Point of Integration (POI) or Point of Delivery (POD) shall be subject to the ET Unauthorized Transmission Increase Charge.

1. Rate

29.28 mills per kilowatt-hour of Billing Energy.

2. Billing Factor

The Billing Energy shall be the amount of energy that exceeds the monthly Contract Energy at specified POIs or PODs.

C. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

D. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

Schedule IS–96—Southern Intertie Transmission Rate

Section I. Availability

This schedule supersedes IS–95 and is available for firm and nonfirm transmission service on the Southern Intertie. Service under this schedule is subject to BPA’s General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures.

Section II. Rate

The rates below apply to both north-to-south and south-to-north transactions.

A. Nonfirm Transmission Rate

The charge shall not exceed 3.53 mills per kilowatt-hour of Billing Energy.

B. Firm Transmission Rate

The charge shall be 1 or 2.

1. Embedded Cost

$0.740 per kilowatt per month of Billing Demand, and 1.77 mills per kilowatt-hour of Billing Energy.

2. Opportunity Cost

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.B.1.

Section III. Billing Factors

A. Nonfirm Transmission

For nonfirm service under section II.A., the Billing Energy shall be the monthly sum of the scheduled kilowatt-hours, plus the monthly sum of kilowatt-hours allocated but not scheduled. The amount of allocated but not scheduled kilowatt-hours that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Southern Intertie capacity. The amount of allocated but not scheduled kilowatt-hours that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. Firm Transmission

For firm transmission service under section II.B.1., the Billing Demand shall be the Transmission Demand as specified in the agreement. The Billing Energy for firm transmission service shall be the monthly sum of scheduled kilowatt-hours, unless otherwise specified in the agreement.

For firm transmission service under section II.B.2., the billing factors shall be specified in the agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support IS transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

C. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service will be subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

D. Rates Applicable to IS Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

Schedule IN–96 Northern Intertie Transmission Rate

Section I. Availability

This schedule supersedes IN–95 and is available for firm and nonfirm transmission service on the Northern Intertie. Service under this schedule is subject to BPA’s General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures.

Section II. Rate

The rates below apply to both north-to-south and south-to-north transactions.

A. Nonfirm Transmission Rate

The charge shall not exceed 0.63 mills per kilowatt-hour of Billing Energy.

B. Firm Transmission Rate

The charge shall be 1 or 2.

1. Embedded Cost

$0.115 per kilowatt per month of Billing Demand, and 0.31 mills per kilowatt-hour of Billing Energy.

2. Opportunity Cost

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.B.1.

Section III. Billing Factors

A. Nonfirm Transmission

For nonfirm service under section II.A., the Billing Energy shall be the monthly sum of the scheduled kilowatt-hours.

B. Firm Transmission

For firm service under section II.B.1., the Billing Demand shall be the Transmission Demand specified in the agreement. The Billing Energy for firm service shall be the monthly sum of the scheduled kilowatt-hours, unless otherwise specified in the agreement.

For firm transmission service under section II.B.2., the billing factors shall be specified in the agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support IN transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

C. Reservation Fee for Transmission Capacity

Customers who request new or increased firm transmission service under this rate and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.O. of the General Rate Schedule Provisions.

D. Rates Applicable to IN Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

Schedule IE–96—Eastern Intertie Transmission Rate

Section I. Availability

This schedule supersedes IE–95 and is available for nonfirm transmission service on the Eastern Intertie. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The charge shall not exceed 1.89 mills per kilowatt-hour of Billing Energy.

Section III. Billing Factors

Billing Energy shall be the monthly sum of the scheduled kilowatt-hours, unless otherwise specified in the Agreement.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support IE transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

Schedule MT–96—Market Transmission Rate

Section I. Availability

This schedule supersedes MT–95 and is available for transmission service for transactions using Federal Columbia River Transmission System facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA—s Billing Procedures.

Section II. Rate

The charge shall be determined in advance by BPA. The charge shall be based on the duration of the proposed transaction and shall not exceed the following rates.

A. Hourly Rate

The maximum charge shall be 6.5 mills per kilowatt-hour where the total hourly revenues from a given transaction during a calendar day shall not exceed the product of the Daily rate and the maximum demand scheduled during such day.

B. Daily Rate

The maximum charge shall be $.105 per kilowattday where the total demand charge revenues in any consecutive 7-day period shall not exceed the product of the Weekly rate and the highest demand experienced on any day in the 7-day period.

C. Weekly Rate

The maximum charge shall be $.52 per kilowattweek.

D. Monthly Rate

The maximum charge shall be $2.27 per kilowattmonth.

Section III. Billing Factors

The billing factors shall be specified in advance by BPA, as to representing the transmission service use or reservation.

Section IV. Other Provisions

A. Ancillary Services

Ancillary services that may be required to support MT transmission service are available under the APS rate schedule.

B. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.N. of the General Rate Schedule Provisions.

Schedule UFT–96—Use-of-Facilities Transmission Rate

Section I. Availability

This schedule supersedes UFT–95 unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA—s Billing Procedures.

Section II. Rate

The monthly charge per kilowatt of Transmission Demand specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

Section III. Determination of Transmission Rate

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and which are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands. The annual cost per kilowatt of Transmission Demand for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

A

D

Where:

A=The annual cost of such facility as determined in accordance with A.1. above.

D=The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

The annual cost per kilowatt of facilities listed in the agreement which are owned by another entity, and used by BPA for making deliveries to the transferee, shall be determined from the costs specified in the agreement between BPA and such other entity.

Section IV. Determination of Billing Demand

Unless otherwise stated in the agreement, the factor to be used in determining the kilowatts of Billing Demand shall be the largest of:

A. The Transmission Demand in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. The Ratchet Demand.

Schedule AF–96 Advance Funding Rate

Section I. Availability

This schedule is available to customers who execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA. Service under this schedule is subject to BPA's General Rate Schedule. Bills shall be rendered and payments due pursuant to BPA's Billing Procedures.

Section II. Rate

The charge is the sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement.

Section III. Payment

A. Advance Payment

Payment to BPA shall be specified in the agreement as either:

1. A lump sum advance payment;
2. Advance payments pursuant to a schedule of progress payments; or
3. Other payment arrangement, as determined by BPA.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. Adjustment to Advance Payment

BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs pursuant to BPA's Billing Procedures.

Schedule TGT–96

Townsend-Garrison transmission rate

Section I. Availability

This schedule supersedes TGT–95 and shall apply to all agreements which provide for the firm transmission of electric power and energy over transmission facilities of BPA's section of the Montana [Eastern] Intertie. Service under this schedule is subject to BPA's General Rate Schedule Provisions and Adjustments, Charges, and Special Rate Provisions. Bills shall be rendered and payments due pursuant to BPA—s Billing Procedures. Service under this schedule is subject to BPA's General Rate Schedule Provisions. Bills shall be rendered and payments due pursuant to BPA—s Billing Procedures.

Section II. Rate

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be either a surplus or a deficit. Such surpluses or deficits for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from nonfirm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower will be the unit rate.

If the government provides firm transmission service in its section of the Montana [Eastern] Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by the government for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer. During an estimated 1- to 3-year period following the commercial operation of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500-kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge.

However, starting 1 month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

A. Nonfirm Transmission Charge

This charge will be filed as a separate rate schedule and revenues received thereunder will reduce the amount of revenue to be collected under the Intertie Charge below.

B. Intertie Charge for Firm Transmission Service

Intertie Charge = [((TAC/12-NFR) × (CR–EC) TCR]

Section III. Definitions

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500-kV Transmission line including terminals, and prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) Interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs which are appropriately allocable to such facilities; and (4) payments made pursuant to section 7(m) of Public Law 96–501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by the government on account of any reduction in Transmission Demand, termination or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Nonfirm Revenues, which are equal to: (1) the product of the Nonfirm Transmission Charge described in II(A) above, and the total nonfirm energy transmitted over the Townsend-Garrison line segment under such charge for such month; plus (2) the product of the Nonfirm Transmission Charge and the total nonfirm energy transmitted in either direction by the Government over the Townsend-Garrison line segment for such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500-kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I; and (2) the Government's firm capacity requirement. The Government's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer which is the product of: (1) the ratio of investment in the Townsend-Broadview 500-kV transmission line to the investment in the Townsend-Garrison 500-kV transmission line; and (2) the capacity which the Government obtains in the Townsend-Broadview 500-kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

F. *General Rate Schedule Provisions (GRSPs):* This section contains the combined GRSPs for power and transmission rates. The GRSPs contain detailed descriptions of all adjustments, charges, and special rate provisions, and definitions of products and services and of rate schedule terms:

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

A. Approval of Rates

These 1996 wholesale power and transmission rate schedules and General Rate Schedule Provisions (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 GRSPs effective on October 1, 1996, 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 1996 wholesale power and transmission rate schedules and the GRSPs associated with these schedules supersede BPA's 1995 rate schedules (which became effective October 1, 1995) to the extent stated in the Availability section of each rate schedule. These schedules and 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 (Pub. L. 88–552), the Federal Columbia River Transmission System Act (Pub. L. 93–454), the Northwest Power Act (Pub. L. 96–501), and the Energy Policy Act of 1992 (Pub. L. 102–486).

These 1996 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

C. 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 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. If a portion of the customer's service area is subject to the surcharge, then the amount of the surcharge shall equal 10 percent of the total charge for all PF and NR power purchases multiplied by the ratio of: (a) the Purchaser's total retail load that is subject to the surcharge; and (b) the customer's total retail load.

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for any portion of power purchased under each rate schedule subject to the surcharge. The level of the residential surcharge will be determined by dividing the customer's residential load not covered by a BPA-approved Model Conservation Standards (MCS) residential plan by the customer's total retail load, rounding the result to the nearest one-tenth of a percent and multiplying the resulting percentage by 0.10. The level of the commercial surcharge will be determined by dividing the customer's commercial load not covered by a BPA-approved MCS commercial plan by the customer's total retail load, rounding the result to the nearest one-tenth of a percent and multiplying the resulting percentage by 0.10. The residential or commercial surcharge (one or the other, but not both for any one customer) will be applied to all power purchases and/or exchanges made by the customer under the applicable rate schedules, using the Council's surcharge methodology, and will be applied subsequent to any other rate adjustment.

B. 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 22.56 mills per kilowatt-hour.

2. The approximate cost contribution of different resource categories to each rate schedule is as follows:

Rate schedule	Resource cost contribution	
	Federal base system (percent)	New resources (percent)
PF–96.2	100	0
PF–96.5	100	0
IP–96.2	77.69	22.31
IP–96.5	77.69	22.31
NR–96.2	77.69	22.31
NR–96.5	77.69	22.31
FPS–96	77.69	22.31

C. Curtailment Charge (IP Only)

Curtailment charges are charges assessed pursuant to section 9 of a DSI's 1981 Contract for failure to purchase an amount of power equal to 75 percent of the DSI's Operating Demand.

D. Deviation Adjustment

The Deviation Adjustment, described below, applies to Partial Requirements Purchasers under the 1996 Contract. In addition, for Full Requirements customers who purchase under 1996 Contracts, the Deviation Adjustment applies to those customers who elect to have their billing factor for Load Shaping reduced by an Industrial Exemption. In addition, the Deviation Adjustment applies to purchasers under the Power Shortage rate.

1. Definition of ''Deviation''

Deviation is the difference between the quantity of power that was actually taken from BPA (Actual) and the quantity the customer should have taken pursuant to its power sales contract (Obligation). If a customer's Actual exceeds its Obligation, the deviation is considered a ''positive'' deviation; if its Actual is less than its Obligation, the deviation is termed ''negative.''

2. The Customer's Purchase Obligation

The customer's purchase Obligation is a function of whether the customer is purchasing BPA's Load Shaping product. The actual description of the Purchaser's Obligation is provided in the Purchaser—s 1996 Contract.

3. Application of the Deviation Adjustment

The Deviation Adjustment is applied differently to customers purchasing Load Shaping and those not purchasing Load Shaping. Authorized Deviations are determined and charged for first, followed by Unauthorized Deviations.

a. Authorized Deviations

1. Load Shaping Purchasers

The Authorized Deviation for any purchaser who is buying BPA's Load Shaping product is included in the PF, NR, and IP billing factors; there is no separate adjustment for Authorized Deviations.

2. Other Purchasers

All other Purchasers who are subject to the Deviation Adjustment are eligible for an Authorized Deviation Adjustment. (In addition, they may be subject to the Unauthorized Deviation Charge below.) The Purchaser shall pay the established PF, NR, or IP rate, as applicable, for the authorized deviation.

b. Unauthorized Deviations

1. Unauthorized Deviation Charge

a. Demand Charge: Demand Charge from applicable power rate schedule.
b. Energy Charge: 100 mills per kWh in all months of the year.

2. Application of the Unauthorized Deviation Charge

Application of the Unauthorized Deviation Charge consists of three separate calculations, each of which is completed for each purchaser.

Positive Deviations

BPA will charge for positive deviations on a monthly basis at the rate specified above. (There is no additional charge for negative deviations, but the customer is not relieved of its take-or-pay obligation for negative deviations.)

Rate Period Excessive Purchases

If, in the last month of the purchase period, BPA determines that the Purchaser has taken more power than it is entitled to take to serve its actual Retail Load for the purchase period, then the Purchaser shall be subject to the Unauthorized Deviation Charge for all such excessive purchases.

Diverted Power Adjustment Deviations

If, in the last month of the purchase period, the Purchaser has not taken return of all of its Diverted Power (as described in the Billing Procedures), then the Purchaser must pay BPA the Unauthorized Deviation charge for all Diverted Power that was not returned to the Purchaser's system during the rate period.

E. Election Process

5-Year Rate Election

Any purchaser, except utilities participating in the residential exchange under section 5(c) of the Northwest Power Act, must elect an amount of power to be purchased under the applicable 5-year rates (PF–96.5, IP–96.5 or NR–96.5). The 5-year rate shall apply to purchasers who purchase power from BPA under either the 1981 or 1996 Contract and who comply with the requirements below.

1. Subscription Options

The amount of power that customers can purchase under the 5-year rate shall be based on one of the following methods.

a. Percentage of Load Option

This option is available only to: (a) Metered Requirements Customers and Actual Computed Requirements Customers as designated in the 1981 Contracts; and (b) Full Requirements Customers and Partial Requirements Customers as designated in the 1996 Contracts who elect to purchase Load Shaping from BPA. This option is not available for service to New Large Single Loads (NLSL). Purchasers eligible to use this option may select a single percentage equal to or less than 100 percent for the 5-year period. If a purchaser selects less than 100 percent, the remaining power purchased from BPA shall be billed at the PF–96.2, IP–96.2, or NR–96.2 rate, as appropriate. For utility purchasers under 1981 Contracts using this option, the amount of subscribed load under the 5-year rate shall be a percentage of the purchaser's Measured Demand and Energy. For DSIs purchasing under a 1981 Contract, the amount of subscribed load at the 5-year rate shall be a percentage of the purchaser's operating level and measured energy. For Full and Partial Requirements utility and DSI customers under 1996 Contracts, the amount of subscribed load under the 5-year rate shall be a percentage of the purchaser's total actual Retail Load.

b. Block of Power Option

This option is available to all purchasers except those serving New Large Single Loads. For purchasers using this option, the amount of subscribed load at the 5-year rate shall be the amount of demand and energy as specified by the purchaser. Purchasers using this option cannot specify an amount of power that exceeds their contract entitlements. Priority Firm Power, New Resource Firm Power, and Industrial Firm Power provided in excess of the amount subscribed will be billed at the appropriate 2-year rate. Purchasers under the 1996 Contract using this option must also specify an amount of power under the appropriate 2-year rate, as described in the contract.

c. Consumer Facility Option

This option is available to purchasers serving one or more New Large Single Loads. Purchasers under this option must elect to purchase under *either* the NR–96.2 rate or the NR–96.5 rate to serve all of that purchaser's NLSL load(s). For purchasers using this option, the amount of subscribed load to be served shall be the sum of the measured amounts of power (demand and energy) at all designated consumer facilities.

2. Notification Requirements

Purchaser must notify BPA, no later than August 1, 1996, of their election to purchase power under the applicable 5-year rate.

a. Purchasers Under 1981 Contracts

For customers continuing to receive service under the 1981 Contract, such notification shall be in writing and must specify the amount of power that a purchaser agrees to purchase exclusively from BPA (subscription amount) over the 5-year rate period, using either the percentage of load option, the block of power option, or the consumer facility option (Subscription Options) as described above.

Purchasers selecting the percentage of load option must specify a single percentage that will apply in each month of the 5-year period.

Purchasers selecting the block of power option must specify the amount of demand, and the amount of energy for HLH and LLH, for each month of the first 2 years in which the rate is effective, October 1, 1996, through September 30, 1998. For the remaining 3 years of the rate, FYs 1999, 2000, and 2001, the purchasers selecting the block of power option must specify annual amounts of demand, HLH energy, and LLH energy. Annual subscription amounts for years 3–5 cannot exceed the annual amounts for years 1–2 unless the increase is due to load growth. Purchasers will specify the monthly amounts for FYs 1999–2001 in subsequent notices, based on the previously selected annual amounts. By February 1, 1998, these purchasers must submit to BPA their monthly amounts of demand and HLH and LLH energy for the period beginning October 1, 1999, through September 30, 2000. By February 1, 2000, these purchasers must submit to BPA their monthly amounts of demand and HLH and LLH energy for the period beginning October 1, 2000, through September 30, 2001. Purchasers who fail to submit subsequent monthly amounts shall be deemed to have elected the same monthly shape selected for the period October 1, 1996, through September 30, 1998.

b. Purchasers under 1996 Contracts

Purchasers under 1996 Contracts must elect to purchase power under the 5-year rate through provisions provided in the contract. Such election will occur at the time a purchaser signs this contract, but in no event later than August 1, 1996.

2-Year Rate Election

Priority Firm Power, Industrial Firm Power, and New Resource Firm Power purchasers under the 1996 Contract purchasing all or a portion of their power under a 2-year rate must specify the amount of demand, and the amount of energy for HLH and LLH, for each month of the period October 1, 1996, through September 30, 1998. Subscriptions for the 2-year rate will be made through provisions provided in the contract. PF, NR, and IP purchasers under a 1981 Contract purchasing all of their power under a 2-year rate do not need to make a subscription.

Load Shaping Election

Any purchaser of load shaping, except utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act and purchasers under the Composite Rate, must elect to purchase the product at either the 2-year rate or the 5-year rate. The purchaser must notify BPA no later than August 1, 1996, of its rate election for the load shaping product.

Load Regulation Election

Same as for load shaping, above.

F. Energy Return Surcharge (PF/NR/FPS Only)

Any purchaser:

1. who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the 1981 Contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that Purchaser's Billing Demand and Computed Average Energy Requirement for the billing month, or

2. who purchases capacity under the FPS rate schedule, returns more than 60 percent of its Contract Demand for the billing month during a single offpeak hour, and is subject to the Energy Return Surcharge shall be subject to the following charge for each additional kilowatt-hour so returned:

- 3.63 mills per kilowatt-hour for the months of September-December;
- 3.83 mills per kilowatt-hour for the months of January–March;
- 3.27 mills per kilowatt-hour for the month of April;
- 5.07 mills per kilowatt-hour for the months of May–June;
- 5.37 mills per kilowatt-hour for the month of July;
- 5.77 mills per kilowatt-hour for the month of August.

FPS purchasers are subject to the Energy Return Surcharge stated above unless their agreement with BPA specifically provides otherwise.

G. Guaranteed Delivery Charge (NF Only)

A surcharge of 2.00 mills per kilowatt-hour of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the Standard rate or Market Expansion rate.

H. Industrial Exemption and Industrial Curtailment

Both Industrial Exemption and Industrial Curtailment are available to purchasers under the 1996 Contract only.

Industrial Exemption adjusts the billing factor for Load Shaping by subtracting exempt industrial loads specified by the Purchaser. Each exempted industrial load must be greater than 5 aMW and must be separately metered. The customer is responsible for ensuring that variations from forecast are provided for; deviations may be subject to the Deviation Adjustment.

Industrial Curtailment allows the purchaser to decrease the forecast of its exempt industrial loads during any billing month. The charge is $0.35 per MWh applied to the megawatthours of industrial curtailment rights nominated for the month.

I. Low Density Discount (PF Only)

1. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power (excluding transmission services) purchased under the PF and NR rate schedules by eligible purchasers as defined in section 2, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are not available by the January billing date. The level of the discount shall be determined from the following ratios based on information for the utility's entire system in the Pacific Northwest, regardless of whether the utility has service areas in more than one state or whether the utility is participating in the residential exchange program in more than one state jurisdiction:

a. The kWh/Investment Ratio

The kWh/Investment ratio is calculated by dividing the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm and nonfirm retail loads, sales for resale, and associated losses) by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

b. The Consumers/Mile of Line Ratio

The Consumers/Mile of Line ratio is calculated by dividing the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding the average number of consumers associated with separately billed services for water heating, electric space heating, and security lights) during the previous calendar year by the average number of pole miles of distribution line for such year, calculated by halving the sum of the end-of-year pole mile figures for the previous year and the current year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on average annual data provided in the Purchaser's financial and operating reports which they submit periodically to BPA (usually monthly or quarterly). 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, regardless of whether the utility has service areas in more than one state or whether the utility is participating in the residential exchange program in more than one state jurisdiction. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see 1.a. and 1.b, above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. LDDs issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

2. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six 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 consumers within the region served by BPA;

c. the Purchaser's average retail rate for the reporting year must exceed the average applicable Priority Firm Power rate for the qualifying period by at least 10 percent. For Calendar Year (CY) 1996, the average Priority Firm Power rate shall be the average of the PF–95 Preference rate for 9 months and the PF–96 Preference rate for 3 months. For CY 1997, the average Priority Firm Power rate shall be the PF–96 Preference rate. For Purchasers under the PF–96.2 rate or the PF–96.5 rate, the applicable rate shall be used for the calculation. For customers purchasing a portion of their load under each of the PF–96 rates, an average of the applicable rates shall be calculated, weighting the PF–96.2 rate by the Purchaser's subscription at that rate and the PF–96.5 rate by the Purchaser's subscription at that rate;

d. the Purchaser's kilowatt-hour-to-investment ratio (Ratio 1.a) must be less than 100;

e. the Purchaser's consumers-per-mile ratio (Ratio 1.b) must be less than 12; and

f. the Purchaser must qualify for a discount based on the criteria in section 3, below.

3. Discounts

The Purchaser shall be awarded the lesser of the following discounts, provided such discount does not differ from the Purchaser's current discount by more than one-half of 1 percent per year:

a. 7 percent, or

b. the sum, not to exceed 7 percent, of the two potential discounts for which the Purchaser qualifies based on the qualifying criteria specified in the following table:

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

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

a. the previous year's discount plus one-half percent if the calculated discount exceeds the previous year's discount; or

b. the previous year's discount minus one-half percent if the calculated discount is less than the previous year's discount.

The foregoing formula will be applied each successive year until the then-current calculated discount is fully phased in.

If the Purchaser fails to satisfy eligibility criteria 2.a.-2.e. above, the applicable discount will be zero.

J. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for BPA's nonfirm energy, including any applicable service charges or rate adjustments, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on a formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Customer Notification of the Value of the NF Rate Cap

Prior to the beginning of each calendar month, BPA shall determine the effective NF Rate Cap for that month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. This notification requirement does not apply if BPA does not intend to offer Nonfirm Energy at prices above BPA's Average System Cost (BASC) at any time during a month. BPA shall give the notification to the purchasers at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap is expected to apply. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the 12-year period that the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC+[0.30 * (DEC—BASC)]

where:

BASC=BPA's Average System Cost

DEC=The Decremental Fuel Cost

4. Determination of BPA's Average System Cost (BASC)

BPA's Average System Cost is calculated by dividing BPA's Total System Costs by BPA's Total Annual System Sales, where:

a. BPA's T*otal System Costs* are the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's Total Annual System Sales are the sum of all BPA's system firm and nonfirm energy sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of the Decremental Fuel Cost (DEC)

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. All quantities are to be rounded to the nearest tenth of a mill in making the calculation.

The monthly decremental fuel cost shall be calculated using the following formula:

DEC = [(MGP * WGU) + (MOP * WOU)] / (WGU + WOU)

where:

MGP = the monthly California gas price

WGU = historical gas use in California

MOP = the monthly California petroleum price

WOU = historical petroleum use in California

a. *Determination of MGP, the Monthly California Gas Price.*

MGP = AGP * HGP / 10

where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HGP = the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r) using the following procedures:

i. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which MGPs were reported and rounded to the nearest one-tenth of a cent;

ii. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which MGPs were reported and rounded to the nearest one-tenth of a cent; and

iii. dividing the average monthly California gas price in ''i'' above, by the average monthly California gas price in ''ii'' above, and rounding to the nearest one-tenth, or three significant places.

10 = the factor for converting gas prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatt-hour.

b. *Determination of WGU, Historical Gas Use in California.*

WGU = CGU * HGU

where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of EPM published by the EIA, U.S. Department of Energy.

HGU = the historical relationship between gas consumption in the effective month of the NF Rate Cap (month t) and the month for which gas consumption is reported in EPM (month r) using the following procedures:

i. summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour;

ii. summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour; and

iii. dividing the average consumption of gas in California for the month t as determined in ''i'' above by the average consumption of gas for the month r as determined in ''ii'' above and rounding to the nearest one-tenth, or three significant places.

c. *Determination of MOP, the Monthly California Petroleum Price.*

MOP = AOP * HOP / 10

where:

AOP = same as AGP except the input data is for the average petroleum price (as opposed to the gas price).

HOP = same as HGP, except the data is for the petroleum price (as opposed to the gas price).
10 = the same conversion factor as used for converting the gas data.

d. Determination of WOU, Historical Petroleum Use in California.

WOU = COU * HOU

where:

COU = the same as CGU except the data for monthly net petroleum-fired generation is used instead of the gas data.
HOU = the same as HGU, except the data for petroleum consumption is used instead of the gas data.

6. Changes in Data Sources

In the event that the data used to compute the NF Rate Cap become unavailable, BPA may identify and substitute other data sources for the purpose of calculating the monthly NF Rate Cap. As a result of this data substitution, it may also be necessary to modify the NF Rate Cap methodology to achieve an NF Rate Cap that is substantially equivalent in rate level to that which would have resulted from continued use of the data described in section 5, above.

BPA shall notify interested parties of its intent to substitute data sources or to substitute data sources and change the NF Rate Cap methodology at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason(s) for the proposed changes and describe its proposed alternative. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final data sources and the final NF Rate Cap methodology to differ from BPA's initial proposal. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month in which the new NF Rate Cap parameters (data sources/methodology) become effective.

K. Operating Reserves Adjustment (IP only)

The energy charges stated in the IP–96 rate schedules reflect a 3.05 mills per kilowatthour credit for the operating reserves a DSI provides to BPA pursuant to its power sales contract. If a DSI chooses not to provide operating reserves, a billing adjustment will be made to remove the credit.

L. Phase-In Mitigation

The phase-in mitigation is available for Full or Metered Requirements Preference customers. Phase-in mitigation does not apply to PF purchased under a Residential Purchase and Sale Agreement or an Exchange Transmission Credit Agreement.

1. Eligibility Criteria

To qualify for the phase-in mitigation a purchaser must:

a. be a Full Requirements customer of BPA as designated in the 1996 Contract, or a Metered Requirements customer of BPA as designated in the 1981 Contract;

b. agree to purchase all power from BPA for 5 years under one or more of BPA's 5-year rate schedules; and

c. have a rate increase greater than 9 percent for all BPA power purchases, rounded to the nearest one-tenth of a percent, based on the determination in section 2 below.

2. Determination of Rate Increase for Phase-In Mitigation

The percentage rate increase faced by a Full or Metered Requirements purchaser will be calculated as follows:

a. Apply all applicable 1993 rate schedule (PF, NR, etc.) charges to the individual customer's FY 1996 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

b. Apply all applicable 1996 rate schedule (PF, NR, transmission, etc.) charges to the individual customer's FY 1996 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

c. If the value of 2.b minus the value of 2.a, divided by 2.a, is greater than 9 percent, rounded to the nearest tenth of a percent, the customer may notify BPA by letter to their Account Executive to phase in the 1996 rate increase. Such notice must be received by BPA by September 1, 1996. Purchasers may not apply for mitigation after this time

3. Rate Adjustment

If the purchaser meets the eligibility criteria and requests BPA to phase in its 1996 rate increase, beginning each October 1 of each year BPA will limit the monthly increase in the customer's bill to 9 percent in the first year, with additional 9-percent increments in each subsequent year over the effective period of the 1996 5-year rates.

The adjustment will be based on the difference between: (1) the purchaser's total monthly payment assuming the 1993 rates for the billing month were applied to power purchases for that month; and (2) the purchaser's total monthly payment under the 1996 rates for that month. In the first year, if the difference between the two is equal to or less than 9 percent, no adjustment will be made to the purchaser's monthly bill. If the difference between the two is greater than 9 percent, an adjustment will be made such that the monthly bill to that customer will reflect an increase equal to 9 percent. In subsequent years, no adjustment shall be made if the difference between (1) and (2) above is less than or equal to 18 percent in the second year, 27 percent in the third year, 36 percent in the fourth year, and 45 percent in the fifth year.

M. Preschedule Change Charge

As specified in the APS–96 rate schedule, BPA shall apply the following charge to any customer who changes its preschedules after the close of the preschedule window: $33 per change.

N. Reactive Power Charge

1. Conditions for Application of the Reactive Power Charge

A Purchaser that purchases power under BPA's wholesale power rate schedules or transmission service on the Federal Columbia River Transmission System (FCRTS) under BPA's transmission rate schedules shall be charged for its Reactive Power requirements for such service.

The Reactive Power Charge will apply only to the Purchaser's Reactive Power requirements for which measured data exist. The Purchaser's Reactive Power requirements shall be measured at each point of delivery and at each point of interconnection between BPA and the Purchaser where real power (MW) flow is unidirectional and the Purchaser is taking delivery of real power (either Federal or non-Federal). Points of delivery that are served by transfer over another utility's transmission system will not be subject to a Reactive Power Charge unless: (1) the transferor imposes a reactive power charge on BPA for serving such Purchaser's load; or (2) there are BPA Integrated Network facilities between the Purchaser's points of delivery and the transferor's system. For points of interconnection, the flow of real power must be unidirectional on all hours during the billing month when the FCRTS facilities are in service. The Reactive Power Charge shall also apply to the Purchaser's Reactive Power requirements measured at points of integration where a Purchaser's generating resource is directly connected to the FCRTS, unless the Purchaser's generating resource is either: (1) a synchronous generator equipped with a voltage regulator; or (2) is equipped with Reactive Power control devices that comply with BPA's interconnection standards. Such resource must actively support the voltage schedule at the point of integration at all times, as determined by BPA, for this exemption to apply.

Generating resources that do not satisfy the above criteria shall not be exempt from the Reactive Power Charge. A Purchaser will pay for its Reactive Power requirements at each point only once.

The Purchaser may submit requests to BPA for special consideration of unique circumstances. BPA will consider the request and may make arrangements with the Purchaser to address the special circumstances.

This Reactive Power Charge replaces the Power Factor Adjustment provision included in BPA's 1993 wholesale power rate schedules. Purchasers previously granted Power Factor Adjustment waivers under BPA's prior wholesale power rate schedules shall be subject to the Reactive Power Charge. The charges for a Purchaser's Reactive Power requirements under this subsection shall be subject to the provisions of BPA's Billing Procedures.

2. Rate

BPA will bill the Purchaser for its total Reactive Power requirements at each point each month according to the methodology below.

a. *Reactive Demand*

$0.08 per kVAr of lagging Reactive Billing Demand during HLH in all months of the year.

$0.06 per kVAr of leading Reactive Billing Demand during LLH in all months of the year.

b. *Reactive Energy*

0.16 mills per kVAr for all lagging and leading Reactive Billing Energy during all hours of all months of the year.

3. Billing Factors

a. *Reactive Demand*

The Purchaser's Reactive Billing Demand shall be calculated independently for lagging Reactive Power and leading Reactive Power at each point for which a Reactive Power Charge is assessed.

All reactive demands shall be established in the particular Peak Period (HLH) or Offpeak Period (LLH) hour during which the maximum applicable reactive demand is placed on BPA, regardless of the time of the real power peak.

All reactive demand shall be established on a non-coincidental basis, regardless of whether the Purchaser is billed for real power or transmission on a coincidental or non-coincidental basis, unless:

i. otherwise specified in the agreement between BPA and the Purchaser, or

ii. coincidental billing is, in BPA's sole determination, more practical for BPA.

The Purchaser's Reactive Billing Demand for the billing month shall be the larger of:

i. the measured reactive demand during the billing month, or

ii. the Ratchet Demand for Reactive Power. The Ratchet Demand for Reactive Power is equal to 100 percent of the largest measured reactive demand during the preceding 6-year, 11 month period. The Ratchet Demand for Reactive Power for the 6-year, 11-month period preceding October 1, 1996, will be set at zero.

b. *Reactive Energy*

The Purchaser's Reactive Billing Energy shall be the measured reactive energy delivered at Purchaser's point during the billing month. (This quantity is the absolute value of all measured reactive energy, not the net value created by summing the positive/lagging reactive energy and the negative/leading reactive energy.)

4. Additional Adjustments

a. *Resetting of the Ratchet Demand*

BPA shall reset the Ratchet Demand for the Purchaser's Reactive Power to zero for any point of delivery or point of interconnection if BPA determines that both of the following criteria are met:

i. The Purchaser has reduced its Reactive Power demand at such point to 20 percent or less of its real power demand at such point on all hours in the month following implementation of the corrective action. Corrective action includes installing switchable capacitors or reactors; and

ii. BPA has not incurred capital expenditures to correct the problem in the preceding 6-year, 11-month period.

b. *Adjustment for Reactive Losses*

Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand and Reactive Billing Energy.

O. Reservation Fee for Transmission Capacity

1. Conditions for Application of Reservation Fee

Reservation Fee is available to customers who enter into an agreement for Firm Transmission Service and want to postpone taking such service until a later date. Reservation Fee is available for new service or replacement of existing service. When used to replace existing service, Reservation Fee is intended to reserve transmission capacity:

a. for the integration of resource capacity or load not included in the current service; and/or

b. for new service that uses either expanded or different transmission facilities or requires changes in FCRTS operations.

Reservation Fee will reserve capacity for 1 year. A customer can request yearly extensions up to a total reservation period of 5 years. If during the reservation period, another customer requests service which can only be satisfied out of the reserved capacity, then the customer with the reservation must agree to pay the full monthly charge for the Firm Transmission Service. The charge becomes effective on the date when the competing request was to become effective. In the event the customer with the reservation elects to release the reserved capacity, the Reservation Fees paid for the current and past years will be forfeited.

2. Reservation Fee

The Reservation Fee shall be a nonrefundable fee equal to one-twelfth of the annual cost of Firm Transmission Service, as determined pursuant to the agreement, for each year or fraction of a year in which the Customer chooses to postpone service. The Reservation Fee shall be paid in a lump sum within 30 days of the date the agreement is executed, and, for yearly extensions, within 30 days of the beginning of the extension. The Reservation Fee shall be assessed annually until transmission service begins or the reservation period ends, whichever occurs first. The Reservation Fee shall be specified in the executed agreement for transmission service.

3. Billing Factors

The billing factors shall be the same as the type of transmission service requested, as determined pursuant to the applicable transmission rate schedule.

P. Transitional Service—Application of Rates During Initial Operation Period

Under the 1981 Contract, and as specified in BPA's Billing Procedures, BPA may agree to bill the purchaser for Transitional Service. Transitional Service shall apply to DSIs having new, additional or reactivated plant facilities, and utility purchasers serving industrial purchasers with power purchased from BPA. Transitional Service will not be available under the 1996 Contract.

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the kilowatt Billing Demand for the billing month shall be based on one of the following billing methods, as agreed to by BPA and the purchaser, based on load characteristics and consistent with the procedures outlined in BPA's Billing Procedures. If for any reason agreement is not reached on a billing method, paragraph 1 below shall serve as a default billing method. Reactive power will continue to be billed normally.

1. *Weighted Monthly Average of Daily Billing Demand*

The Billing Demand for each day is the maximum metered amount for any hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

2. *Weighted Monthly Average of Daily HLH Billing Demand*

The Billing Demand for each day is the maximum metered amount for any HLH hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

Q. Unauthorized Increase Charge

If specified in the applicable rate schedule, BPA shall apply the charge for Unauthorized Increase to any purchaser taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

a. Demand Charge: Demand Charge from applicable power rate schedule.

b. Energy Charge: 100 mills per kWh in all months of the year.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an Unauthorized Increase. BPA first shall determine the amount of Unauthorized Increase related to demand and shall treat any remaining Unauthorized Increase as energy-related.

a. *Unauthorized Increase in Demand*

That portion of any Measured Demand hours that exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

1. To a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

2. To a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour,

shall be billed:

1. In accordance with the provisions of the ''Relief from Overrun'' exhibit to the 1981 Contract; or

2. At the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the Purchaser's power sales contract.

b. *Unauthorized Increase in Energy*

The amount of Measured Energy during a billing month that exceeds the amount of energy the purchaser is contractually entitled to take during that month and which cannot be assigned:

1. To a class of power BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

2. To a type of power the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

1. In accordance with the provisions of the ''Relief from Overrun'' exhibit to the 1981 Contract; or

2. At the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

R. Utility Factor

For purchasers under the 1981 Contract, charges for Load Shaping and Load Regulation are multiplied by a utility-specific, monthly Utility Factor.

The Utility Factors to be used for billing will be developed annually based on historical data provided by the customers to BPA. The annual Utility Factor will be based on the customer's historical annual system load and purchases from BPA. Previous calendar year historical data (January 1–December 31) will be used to develop an annual utility factor that will be in effect for the following fiscal year (October 1–September 30). The customer shall submit its end of calendar year Financial and Operating Report and Generation Report (if applicable). BPA will develop the billing factors once they have received all necessary data from customers (usually in April). If a customer has not submitted the required data by June 1, BPA will prepare an estimate of the customer's historical annual system load for the previous calendar year, after consultation with the customer, and prepare the Utility Factor from that estimate. Completed Utility Factors will be provided to the customers. The first effective year for utility factors coincides with the first year of implementation of the new rate structure: October 1, 1996–September 30, 1997. Historical data from the previous calendar year (January 1, 1995–December 31, 1995) will be used to develop the utility factor for this first year. The customer's annual system load (in kWh) is defined as the total of:

(1) Retail load; plus
(2) Utility's own use; plus
(3) Distribution losses; minus
(4) Sales for resale.

The Utility Factor for the applicable fiscal year = customer system load ÷ energy purchases under the 1981 power sales contract for the previous calendar year.

Section III. Definitions

A. Products and Services Offered by BPA

1. Ancillary Services

Ancillary Services are those services necessary to support the transmission of electric power from resources to load while maintaining reliable operation of the FCRTS. Ancillary services include:

Scheduling and Dispatching, Transmission Losses, Control Area Reserves for Resources, Control Area Reserves for Interruptible Purchasers, and Load Regulation.

2. 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 contract rate under the Firm Power Products and Services (FPS) rate schedule.

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 on line 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, shut-down, normal operations, and operations during a shut-down period.

3. Control Area Services

Control Area Services are services that BPA provides to the Purchaser for real-time fluctuations in the Purchaser's power requirements during the delivery hour. With these services, BPA will deliver power to the Purchaser in amounts that change automatically in response to changes in the Purchaser's loads or resource output located in BPA's control area. These services meet the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP) for regulating margin and spinning and non-spinning operating reserves. In addition, BPA may also provide similar services to loads and resources outside BPA's control area. The general category, Control Area Services, includes:

a. Control area reserves for resources;
b. Control area reserves for interruptible purchases;
c. Load regulation;
d. Eccentric load following;
e. Other control area services.

4. Control Area Reserves for Resources

Control Area Reserves for Resources are the control area services necessary to back up generation located in BPA's control area. Control Area Reserves for Resources provides the generation following and operating reserves for the remainder of the delivery hour.

5. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are the operating reserves provided by BPA for interruptible energy delivered to BPA's control area. Interruptible energy is defined as energy deliveries that can be interrupted by the delivering control area during the delivery hour.

6. Eccentric Load Following

Eccentric Load Following provides instantaneous (second-to-second) regulation of firm power supply for a Purchaser's actual real-time eccentric load within the hour. An eccentric load is defined as any specific cyclic customer or consumer load with the ability to change more than 50 MW in level at a rate of greater than 50 MW per minute, regardless of the duration of this change.

7. Firm Capacity without Energy

Firm Capacity without Energy is a product available under the PF–96.2 and NR–96.2 rate schedules to computed requirements customers who hold 1981 Contracts. Customers who buy this product may take power from BPA during HLH and must return the associated energy within 24 hours. This product is also offered under the FPS rate schedule with delivery and return provisions that may differ from those available under the 1981 Contract.

8. Firm Power

Firm Power available at the FPS rate is defined as firm energy with capacity, firm energy without capacity, and/or firm capacity that BPA may make available to the purchaser at BPA's discretion. Energy associated with the delivery of firm capacity must be returned to BPA either before or after delivery of the capacity and in a manner consistent with the agreement between BPA and the Purchaser.

Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Firm Power is guaranteed to be continuously available to the purchaser during the period covered by the commitment, except for reasons of certain uncontrollable forces. Firm Power may be used to meet the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP) for Operating Reserves. Firm Power is also available for various unbundled products, including:

a. Construction, test and start-up, and station service;
b. Power supplied for emergency use;
c. Replacement of lost generation during forced outages;
d. Replacement of lost generation during planned outages;
e. Displacement of higher-cost firm capacity resources which are otherwise available to meet the purchaser's load;
f. Supplemental non-spinning operating reserves; and
g. Other purposes.

9. Firm Transmission Service

Firm Transmission Service is the transmission service that BPA provides except for transmission service scheduled as nonfirm. If the firm service is provided pursuant to an agreement, the terms of the agreement may further define the service.

10. Industrial Curtailment

Industrial Curtailment allows the purchaser to decrease the forecast of its exempt industrial loads (see Industrial Exemption).

11. Industrial Exemption

Industrial Exemption adjusts the billing factor for Full Load Shaping to allow a customer to exempt industrial loads from load shaping charges. With the exemption, the customer is responsible for covering variations in the industrial load, except for loads also covered by Industrial Curtailment. The exempted industrial load must be greater than 5 aMW and must be separately metered.

12. 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. No Outage Adjustment shall be made for power restricted to provide reserves.

13. Load Regulation

Load Regulation is the instantaneous (second-by-second) regulation of the supply of firm power that BPA provides to follow variations in customer's loads within the hour. The amount of Load Regulation provided is related to the customer's retail load.

14. Load Shaping

Full Load Shaping provides coverage for the monthly difference between a utility purchaser's actual and forecasted retail loads. (Any deviations due to changes in resource operations are subject to the Unauthorized Deviation Adjustment or Unauthorized Increase Charge.) With the purchase of this product, a Purchaser will pay for only the power demand, HLH energy, and LLH energy it takes. Similarly, DSI Load Shaping, available to DSIs under a 1996 Contract only, provides coverage for a variation of up to 15 percent in a DSI customer's actual and forecasted loads due to changes in plant operations. Economic displacement is not allowed under DSI Load Shaping.

A separate product, Partial Load Shaping, is available to utilities under 1996 Contracts only. Partial Load Shaping allows the Purchaser to specify an amount of load shaping it will purchase. If the Purchaser's retail load exceeds its forecast, BPA will provide additional demand and energy, limited to the amount specified by the customer. If the Purchaser's retail load is lower than forecast, BPA will relieve the take-or-pay obligation up to the amount of load shaping specified.

15. 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, and

b. For firm power purchased by investor-owned utilities (IOUs) pursuant to power sales contracts with BPA.

New Resource Firm Power is to be used to meet the Purchaser's actual firm load within the Pacific Northwest. 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.

16. 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–96. Nonfirm energy also may be supplied under the NF–96 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. However, 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.

17. Nonfirm Transmission Service

Nonfirm Transmission Service is interruptible transmission service.

18. Power Supplied for Emergency Use

Power Supplied for Emergency Use is electric energy and/or capacity that has been supplied by BPA under the FPS rate schedule:

a. For use during an emergency on the Purchaser's system, or

b. Following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may be provided under exchange agreements, and payment for that power made in accordance with the terms of those agreements.

19. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers and for direct consumption 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 Purchase and Sale Agreements (RPSA). Priority Firm Power is not available to serve New Large Single Loads.

Power purchased under the rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Deliveries of Priority Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

20. Reserve Power

Reserve Power is firm power sold to a Purchaser:

a. In cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;

b. To provide service when no other type of power is deemed applicable; or

c. To serve the Purchaser's firm power loads under circumstances in which BPA does not have a power sales contract in force with the purchaser.

Deliveries of Reserve Power may be reduced or interrupted either as a result of an uncontrollable force or when necessitated by emergencies, system maintenance requirements or other factors related to continuity of service.

21. Residential Purchase and Sale Agreement (RPSA) Power

RPSA Power is power BPA sells to a Purchaser pursuant to the Purchaser's Residential Purchase and Sale Agreement (RPSA) with BPA. Under section 5(c) of the Northwest Power Act, BPA ''purchases'' power from each RPSA customer at that 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.

22. Scheduling and Dispatching

Scheduling and Dispatching consists of all scheduling and generation-related dispatch activities including: real-time operation and control of generation resources located within BPA's control area; prescheduling; associated scheduling and dispatch; confirmation and verification of individual schedules, including preschedules and real-time or after-the-fact changes; associated losses; and net interchange between control areas.

a. Scheduling or prescheduling is the procedure to establish schedules between control areas for a predetermined or before-the-fact use of the FCRTS.

b. Generation-related dispatch is all the dispatch activity related to the operation of generation located within BPA's control area including, but not limited to, AGC and required current-hour schedule changes.

c. Preschedule is the process of identifying and activating accounts for the hourly energy transactions that will be implemented on the following day or days.

d. Preschedule Change is any change to a Preschedule transaction after the close of the Preschedule Window and prior to the hour of real-time implementation of the schedule.

e. Preschedule Window is the period of time during the commonly recognized workday when hourly schedules for the next day or days are prepared and entered into the energy management system.

f. Real-Time Change is any change to a Prescheduled transaction during the current day and any addition to a customer—s total daily schedules submitted during the Preschedule Window.

g. After-the-Fact Change is any change to a scheduled transaction for a historical day or days, including changes required due to a customer's scheduling error.

23. Shaping Services

Shaping Services are services provided by BPA to a Purchaser to shape the output of the Purchaser's resource (or purchase) to the Purchaser's load. Shaping services may be provided on an hourly, daily, weekly, monthly, seasonal, or other basis, and may include advance delivery of the resource (or purchase) to the load. Shaping services are available under the FPS rate schedule.

24. Shortage Power

Shortage Power is energy or energy with capacity, provided by BPA to a

Purchaser to serve such purchaser's regional load under circumstances where the Purchaser is in danger of curtailing firm load even though the Purchaser is operating all available resources and exercising all contractual rights to firm power to the maximum level feasible. In the event of a state-ordered or regionwide load curtailment, a power deficiency is deemed to exist for those Purchasers whose power supply condition is in part causally related to the State(s)-initiated load curtailment.

25. Transitional Service

Transitional Service is service that BPA provides to a DSI or utility customer that has a large industrial load that is being brought on-line. The load may be a new industrial plant, a major addition to an existing industrial plant, or reactivation of an existing industrial plant or major portion thereof. Pursuant to its agreement with the customer, BPA will serve the load and calculate the customer's monthly Billing Demand to account for the daily variations in the industrial load. In order to receive this service, the BPA customer must meet the eligibility requirements set forth in BPA's Billing Procedures.

26. Transmission Losses

Transmission losses are the power losses associated with the transmission of power over the FCRTS. The loss factor that represents the amount of losses for a specific transaction is included in the wheeling agreement or the rate schedule or tariff.

27. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

28. Variable Industrial Power

Variable Industrial Power is Industrial Firm Power that is sold at the VI–96 rate, consistent with the terms and conditions of the Variable Rate Contract between BPA and the Purchaser.

B. Definition of Rate Schedule Terms

1. 1981 Contract

The ''1981 Contract'' refers to the initial power sales contracts that BPA executed with its Pacific Northwest customers pursuant to the requirements of the Northwest Power Act. Most of these contracts were executed in 1981, but some are dated ''1984'' or later. For purposes of these rate schedules, any such contract effective prior to October 1, 1996, is referred to for convenience as a ''1981 Contract.''

2. 1996 Contract

Contracts for the sale of firm power to Pacific Northwest customers pursuant to the requirements of the Northwest Power Act are termed the ''1996 Contracts'' if they are effective on or after October 1, 1996.

3. Auxiliary Demand (1981 DSI Contract)

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. Auxiliary Power is power in excess of the DSI's Operating Demand. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's 1981 Contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power rate schedule.

4. Billing Demand (Energy)

The Purchaser's Billing Demand (Energy) is the amount of capacity (energy) to which the demand (energy) charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand (Energy) quantity for each product. BPA establishes Billing Demand and Billing Energy quantities for both active power (kilowatts/kilowatt-hours) and reactive power (kilovars and kilovarhours).

Various adjustments may be made to billing demand. At any POD that has an unbalanced phase current problem, BPA shall calculate the Billing Demand by multiplying the largest of the adjusted Integrated Demands on any phase during the billing month by three. BPA may continue this billing procedure until the Purchaser has made the necessary system corrections. Billing Demand also may be adjusted for certain outages (providing the Purchaser an Outage Credit) as specified in the Purchaser's agreement with BPA and pursuant to BPA's Billing Procedures.

5. BPA Operating Level (1981 DSI Contract)

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;
b. Curtailed Demand; or
c. Restricted Demand.

Each DSI must request service from BPA for each billing month in accordance with the terms of its power sales contract. The requested level of service under the 1981 Contract will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request, and BPA may agree to provide, a level of service for the Offpeak Periods that differs from that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an Unauthorized Increase.

Any DSI whose Measured Demand during any single hour exceeds the BPA Operating Level for that hour shall be subject to an Unauthorized Increase charge for each kilowatt and kilowatt-hour of Unauthorized Increase associated with each such overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule and the Variable Industrial Power rate schedule. During the Peak Period, the BPA Operating Level may be no greater than the Operating Demand for the billing month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

6. Calculated Energy Capacity

Calculated Energy Capacity is BPA's estimate of the amount of energy load (aMW) that a DSI would consume if its plant(s) is operating at full capacity. It is the billing factor for DSI Load Shaping.

7. Composite Rate

The Composite Rate applies to PF–96.5 Purchasers under 1981 and 1996 Contracts. Only customers whose average annual energy loads during the 5-year purchase period, as forecasted by BPA, are 25 average annual MW or less are eligible to purchase at this rate. The composite rate is a weighted average rate that takes into account the relative cost of typical quantities of each product purchased, including generation demand and energy, load shaping, and load regulation.

8. Computed Average Energy Requirement (1981 Utility Contract)

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. Sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. Sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. Sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

9. Computed Energy Maximum (1981 Utility Contract)

The Computed Energy Maximum equals the Computed Average Energy Requirement (CAER) multiplied by the number of hours in the billing month. HLH Computed Energy Maximum equals the CAER multiplied by the number of HLH in the month; LLH Computed Energy Maximum equals the CAER multiplied by the number of LLH in the month.

10. Computed Maximum Requirement (1981 Utility Contract)

The Purchaser's Computed Maximum Requirement is the maximum amount of power that BPA is obligated to deliver to the Purchaser during the HLH of a month. The Computed Maximum Requirement is defined in section 17(g)(1) of the Purchaser's 1981 Contract as the greater of the Purchaser's Computed Peak Requirement and Computed Average Energy Requirement unless the terms of section 7 (''Allocation Provisions in the Event of Planning Insufficiency'') apply.

11. Computed Peak Requirement (1981 Utility Contract)

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

12. Computed Requirements Customer (1981 Utility Contract)

A Computed Requirements Customer is a Purchaser of Priority Firm and/or New Resource Firm Power who is designated as a computed requirements customer by the terms of its 1981 contract.

13. Contract Demand

The Contract Demand shall be 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. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatt-hours shall be deemed, for the purpose of these GRSPs, to refer to the term ''Contract Energy.''

14. Contract Energy

Contract Energy is the maximum number of kilowatt-hours that BPA agrees to make available subject to any limitations included in the contractual agreement between BPA and the Purchaser. Contract Energy may refer to an energy purchase from BPA or to an amount of energy that BPA agrees to transmit over the FCRTS.

15. Curtailed Demand (1981 DSI Contract)

A Curtailed Demand is the number of kilowatts of Industrial Firm Power during the billing month which results from a DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of Industrial Firm Power may curtail its demand according to the terms of its 1981 contract (which permits up to three levels of Curtailed Demand each month).

16. Customer's Load

Customer's Load is the customer's Network Load measured during the hour of the Monthly Transmission Peak Load. For customers with 1981 Contracts, Customer's Load is the power taken under 1981 Contracts during the hour of the Monthly Transmission Peak Load.

17. Decremental Cost

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

a. All identifiable costs (expressed in mills per kilowatt-hour) associated with the use of a displaceable thermal resource or end-user 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 per kilowatt-hour) 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.

18. Direct Assignment Facilities

Direct Assignment Facilities are transmission facilities which are constructed by BPA for the sole use/benefit of facilitating a specific request for transmission service, the costs of which are directly assigned to the transmission customer requesting service.

19. Direct Service Industry (DSI) Delivery

The DSI Delivery segment is the portion of the FCRTS that provides service to DSI customers at voltages of 34.5 kV and below.

20. Eastern Intertie

The Eastern Intertie is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

21. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatt-hours).

22. Federal Columbia River Transmission System

The Federal Columbia River Transmission System (FCRTS) is comprised of the transmission facilities of the Federal Columbia River Power System, which includes all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

23. Full Requirements Customer (1996 Contract)

As currently proposed by BPA, a Full Requirements Customer is a customer that has not been designated by BPA as a Partial Requirements Customer under the terms of its 1996 Contract. This term will be further defined as 1996 Contracts are developed. For purposes of these rate schedules, Full Requirements Customers are those purchasers under 1996 Contracts: (a) with no resource; or (b) that have contracted for services with BPA or another party for their resource(s) so that the purchaser retains Full Requirements status.

24. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the Peak Period (6 a.m. to 10 p.m., Monday through Saturday).

25. Integrated Demand

Integrated Demand is the quantity derived by mathematically ''integrating'' kilowatt-hour deliveries over a 60-minute period.

26. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the Offpeak Period (10 p.m. to 6 a.m. Monday through Saturday and all hours Sunday).

27. Main Grid

As used in the FPT rate schedule, the Main Grid is that portion of the Network facilities with an operating voltage of 230 kV or more.

28. Main Grid Distance

As used in the FPT rate schedules, Main Grid Distance is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

29. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid Interconnection Terminal refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

30. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, Main Grid Miscellaneous Facilities refers to switching, transformation, and other facilities of the Main Grid not included in other components.

31. Main Grid Terminal

As used in the FPT rate schedules, Main Grid Terminal refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

32. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand purchased from BPA under the applicable rate schedule. The Measured Demand is computed for the hour of the Monthly Transmission Peak Load. 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 agreed by the parties. 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 amounts (Unauthorized Increases under the 1981 Contract and Unauthorized Deviations under the 1996 Contract) are considered a separate class of power when determining Measured Demand and are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined in the Purchaser's agreement with BPA and in BPA's Billing Procedures, BPA shall exclude 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 Bonneville determines that such facilities have been adequately maintained and prudently operated.

Partial interruptions shall be converted to an equivalent outage of total Measured Demand.

33. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is purchased from BPA under the applicable rate schedule during a particular season or diurnal period (HLH or LLH). 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 agreed by the parties. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Measured Energy for Load Shaping and Load Regulation includes both PF and NLSL (NR) purchases. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered ''unauthorized.'' Unauthorized amounts (Unauthorized Increases under the 1981 Contract and Unauthorized Deviations under the 1996 Contract) are considered a separate class of power when determining Measured Energy and are billed in accordance with the provisions of these GRSPs.

34. 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.

35. Metered Energy

The Metered Energy for a purchaser shall be the number of kilowatt-hours 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.

36. Metered Requirements Customer

A Metered Requirements Customer is a customer that has been designated as such under the terms of its 1981 Contract.

37. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the monthly peak loading on the FCRTS for the billing month.

38. Network (or Integrated Network)

The Network is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, as defined in BPA's Segmentation Study.

39. Network Upgrades

Network Upgrades are modifications and/or additions to transmission-related facilities that are integrated with and support BPA's Network Transmission System to satisfy, at least in part, an application for transmission service as well as provide for the general benefit of all users of such Network Transmission System.

40. Northern Intertie

The Northern Intertie is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of two 500-kV lines between Custer Substation and the United States-Canadian border, one 500-kV line between Custer and Monroe Substations, two 230-kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

41. Offpeak Period

The Offpeak Period (or LLH) includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 6 a.m., Monday through Saturday, and all hours Sunday.

42. Operating Demand (1981 DSI Contract)

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's 1981 Contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. The hourly demand which the purchaser may impose on BPA; and

b. The total amount of energy during a billing month which the DSI is entitled to purchase from BPA.

43. Opportunity Cost

Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. Opportunity Cost shall be determined consistent with FERC policy.

44. Partial Requirements Customer (1996 Contract)

As currently proposed by BPA, a Partial Requirements Customer is a Purchaser (utility, Federal Agency, or DSI) that is designated as a Partial Requirements Customer by the terms of its 1996 Contract. This term will be further defined as 1996 Contracts are developed. For purposes of these rate schedules, Partial Requirements Customers are those purchasers under 1996 Contracts that dedicate generation resources or purchases to serve their retail load in specific amounts.

45. Peak Period

The Peak Period (or HLH) includes the hours from 6 a.m. to 10 p.m., Monday through Saturday.

46. Phase-In Mitigation

Phase-In Mitigation is available to Full and Metered Requirements Preference Purchasers who are purchasing their firm requirements under one or more of BPA's 5-year rate schedules and whose 1996 rate increase for BPA purchases is at least 9 percent. If the purchaser meets the eligibility criteria and requests that BPA phase in its 1996 rate increase, BPA will limit the Purchaser's annual rate increase to 9 percent each year for the 5-year period.

47. Point of Delivery (POD)

A Point of Delivery is where BPA delivers power to a customer. The delivered power will be Federal power to the extent that the customer is purchasing power under BPA's wholesale power rate schedules, and it will be non-Federal power to the extent that the customer is purchasing transmission services from BPA.

48. Point of Integration (POI)

A Point of Integration is a connection point between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

49. Point of Interconnection

A Point of Interconnection is a connection point between the FCRTS and non-BPA facilities where there is a change in facility ownership.

50. 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.

51. Ratchet Demand

The Ratchet Demand in kilowatts is the maximum demand established during a specified period of time either during, or prior to, the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. When the Ratchet Demand is used as a billing factor, BPA shall have specified the following information in the appropriate rate schedules or GRSPs:

a. The period of time over which the ratchet shall be calculated;

b. The type of demand to be used in the calculation; and

c. The percentage (if any) of that demand that will be used to calculate the Ratchet Demand.

In the event that the Purchaser has decreased its demand under the terms of its agreement with Bonneville, Bonneville shall, as necessary, reduce the Ratchet Demand to ensure that it does not exceed the maximum demand permitted under the terms of the Agreement.

52. Reactive Power

Reactive Power is the out-of-phase component of the total voltamperes in an electric circuit. Reactive Power has two components: reactive demand (expressed in kilovars or kVAr) and reactive energy (expressed in kilovarhours or kVArh).

53. Restricted Demand (1981 DSI Contract)

Restricted Demand is the number of kilowatts of Industrial Firm Power that results when BPA has restricted delivery of such power for one clock-hour or more. BPA makes such restrictions pursuant to the terms of the DSI's power sales contract with BPA. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as the number of restrictions.

54. Retail Load

Retail Load for a utility or Federal agency is the purchaser's regional retail energy load during any given time period plus distribution losses and the purchaser's system power requirements. No distinction is made between load that is served with BPA power and load that the customer serves with power acquired from other sources. Retail Load for a DSI is the purchaser's total energy load at facilities eligible for BPA service during any given time period, irrespective of whether the customer has chosen to serve its load with BPA or non-Federal power. Retail Load is the billing factor for Load Shaping and Load Regulation for certain purchasers.

55. Scheduled Demand

The Scheduled Demand in kilowatts is the largest of the hourly demands at which electric energy is scheduled for transmission on the FCRTS or 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 amounts are deemed delivered for the purpose of determining Billing Demand.

56. Scheduled Energy

The Scheduled Energy in kilowatt-hours shall be the sum of the hourly demands at which electric energy is scheduled 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 amounts are deemed delivered for the purpose of determining Billing Energy.

57. Secondary System

As used in the FPT and IR rate schedules, Secondary System is that portion of the Integrated Network facilities with an operating voltage of less than 230 kV.

58. Secondary System Distance

As used in the FPT rate schedules, Secondary System Distance is the number of circuit miles of Secondary System transmission lines between the secondary POI and either the Main Grid or the secondary POD, or between the Main Grid and the secondary POD.

59. Secondary System Interconnection Terminal

As used in the FPT rate schedules, Secondary System Interconnection Terminal refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

60. Secondary System Intermediate Terminal

As used in the FPT rate schedules, Secondary System Interconnection Terminal refers to the first and final terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

61. Secondary Transformation

As used in the FPT rate schedules, Secondary Transformation refers to transformation from Main Grid to Secondary System facilities.

62. Southern Intertie

The Southern Intertie is the segment of the FCRTS which includes, but is not limited to, the major transmission facilities consisting of two 500 kV AC lines from John Day Substation to the Oregon-California border, a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation, and the 500 kV AC Intertie facilities which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

63. Subscription

A Purchaser's Subscription is the amount(s) of a particular product(s) a Purchaser is entitled to purchase from BPA during a billing month. When a Purchaser must provide BPA with its Subscription is specified in the Purchaser's 1996 Contract with BPA.

5-Year Demand Subscription (Substitute ''HLH Energy'' or ''LLH Energy'' for ''Demand'' as appropriate).

The Purchaser's 5-Year Demand Subscription is the maximum amount of capacity (demand), as designated by the purchaser, that the purchaser elects to purchase from BPA under the applicable 5-year rate schedule for each month. A purchaser's demand subscription forms the basis for the monthly billing demand for that purchaser. For purchasers designating a monthly megawatt amount, the 5-Year Demand Subscription for that purchaser's billing month shall be the amount so specified by the purchaser. For DSIs under a 1981 Contract, the amount of subscribed load at the 5-year rate shall be a percentage of the purchaser's operating level and measured energy. For purchasers continuing service under the 1981 Contract who designate a percentage, the 5-Year Demand Subscription shall be determined by taking the specified percentage times the purchaser's Measured Demand. For purchasers under the 1996 Contract, the 5-Year Demand Subscription shall be determined by taking the specified percentage times the purchaser's actual Retail [demand] Load. For purchasers electing service to a New Large Single Load(s) under the NR–96.5 rate, the 5-Year Demand Subscription shall be the total Measured Demand for all designated consumer facilities.

2-Year Demand Subscription (Substitute ''HLH Energy'' or ''LLH Energy'' for ''Demand'' as appropriate).

The Purchaser's 2-Year Demand Subscription is the maximum amount of capacity (demand), as designated by the purchaser, that the purchaser elects to purchase from BPA under the applicable 2-year rate schedule for each month. A purchaser's demand subscription forms the basis for the monthly billing demand for that purchaser. Only purchasers receiving service under the 1996 Contracts are required to subscribe to an amount of demand at the 2-year rate schedule.

64. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable Agreement.

65. Transmission Demand

Transmission Demand is the demand for transmission services as specified in the applicable Agreement.

66. Utility Delivery

The Utility Delivery segment is the portion of the FCRTS that provides service to utility customers at voltages of 34.5 kV and below.

67. Utility Factor

A Utility Factor is the factor BPA applies to the charges for Load Shaping and Load Regulation under the 1981 Contracts. The Utility Factor is developed annually based on historical data provided by the customers to the Account executive or District Sales Office. The annual factor will be based on the customer's historical annual average retail load and average purchases from BPA and applied on a fiscal year basis.

Issued in Portland, Oregon, on June 30, 1995.

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[FR Doc. 95–17374 Filed 7–11–95; 3:38 pm]

BILLING CODE 6450–01–P