Anyone wishing to object to the grant of this license has 60 days from the date of this notice to file written objections along with supporting evidence, if any. Written objections are to be filed with the Office of Naval Research, ONR 00CC, Ballston Tower One, Arlington, Virginia 22217–5660.

FOR FURTHER INFORMATION CONTACT: Mr. R.J. Erickson, Staff Patent Attorney, Office of Naval Research, ONR 00CC, Ballston Tower One, 800 North Quincy Street, Arlington, Virginia 22217–5660, telephone (703) 696–4001.

Dated: April 21, 1995.

M.D. Schetzsle,

LT, JAGC, USNR, Alternate Federal Register Liaison Officer.

[FR Doc. 95–10553 Filed 4–28–95; 8:45 am]

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DEPARTMENT OF ENERGY

Bonneville Power Administration 1995 Wholesale Power and Transmission Rates, Variable Industrial Power Rate Extension (VI–95), and Pacific Northwest Coordination Agreement (PNCA) Rates

AGENCY: Bonneville Power Administration (BPA), DOE.

ACTION: Availability of proposed 1995 wholesale power and transmission rates, variable industrial rate extension (VI–95), Pacific Northwest Coordination Agreement (PNCA) Rates, and order establishing schedule.

SUMMARY: *BPA File No:* WP–95/TR–95, WP–96, TR–96, TC–96. On December 28, 1994, Bonneville Power Administration (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). On March 3, 1995, BPA published a Notice of Additional Prehearing/Settlement Conference for March 15, 1995, 60 FR 11962 (1995). At that prehearing conference, the Hearing Officers were expected to act on several procedural matters and to establish a procedural schedule. The March 3, 1995, Notice also included schedules for a New Rates and Terms and Conditions Proceeding and for an Extension of Current Rates Proceeding. Notice also was given that some issues might be settled by the litigants, causing the proposed schedule to change.

At the Prehearing/Settlement Conference on March 15, 1995, the litigants reported to Hearing Officers about settlement discussions that had been taking place between BPA and its customers. The parties requested, and the Hearing Officers allowed, additional time to complete the settlement process. The Hearing Officers set an additional Scheduling Conference for March 22, 1995, at which time parties to the rate case would be asked to report on the status of the settlement and the Hearing Officers would rule on procedural matters. 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 establish a separate subsequent process to establish a 2-year rate proposal, a 5-year rate proposal, and a proposal for transmission services terms and conditions.

By this notice, BPA announces its proposed 1995 rates to be effective for 1 year beginning on October 1, 1995, and extending through September 1996, and its proposed rates for transactions under the Pacific Northwest Coordination Agreement (PNCA). BPA will publish a separate notice in the **Federal Register** to announce its proposed new power and transmission rates to be effective on October 1, 1996, including new 2- and 5-year rates, and its new transmission services terms and conditions on or around the July 10, 1995, Filing Date established for Docket Numbers WP–96, TR–96, and TC–96.

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 Proceedings; and (2) adopted other procedural rules governing 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., PO Box 12999, Portland, Oregon 97212.

Schedule for WP–95/TR–95:

May 1, 1995—BPA Files Direct Case
May 30, 1995—Parties File Direct Case
June 9, 1995—Close of Participant Comments
June 19, 1995—Litigants File Rebuttal Testimony
June 30, 1995—Cross-Examination
July 10, 1995—Initial Briefs Filed
July 31, 1995—Final Record of Decision

Schedule for WP–96/TR–96 and TC–96:

July 10, 1995—BPA Files Direct Case/Prehearing Conference
September 8, 1995—Parties File Direct Case
October 2, 1995—Close of Participant Comments
October 25, 1995—Litigants File Rebuttal Testimony/BPA Supplemental Testimony
December 4, 1995—Litigants File Rebuttal to Supplemental Testimony
January 3–February 3, 1996—Cross-Examination
February 21, 1996—Initial Briefs Filed
February 28, 1996—Oral Argument
March 25, 1996—BPA Draft Record of Decision/Hearing Officers Recommended Decision
April 15, 1996—Briefs on Exceptions
April 30, 1996—Final Record of Decision

BPA also will be conducting public field hearings. A notice of the dates, times, and locations of the field hearings will be made later through mailings and public advertising.

ADDRESSES: Written comments by participants must be received by June 9, 1995, for WP–95/TR–95 and by October 2, 1995, for WP–96/TR–96/TC–96 to be considered in the Record of Decision (ROD). Written comments should be submitted to the Manager, Corporate Communications—CK; Bonneville Power Administration; PO 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; PO 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; 201 Queen Anne Ave. N., Suite 400; Seattle, WA 98109–1030 (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. Mr. Dennis Metcalf, BPA Transmission Team Lead, is the official responsible for the development of BPA's transmission terms and conditions.

SUPPLEMENTARY INFORMATION:

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I. Introduction

Prior to the March 15, 1995, prehearing conference, BPA determined that its initial proposal should include new 2-year and 5-year rates. 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 of 1995. As part of the settlement discussions, the parties expressed a need for additional time to respond to BPA's new rate designs. BPA believes that without an adjustment to its wholesale and transmission rates for the period October 1, 1995, through September 30, 1996, BPA's ability to satisfy its statutory obligations could be impaired. The rate case schedule adopted by the Hearing Officers on March 22, 1995, meets both BPA's and the parties' needs. The schedule affords the parties a hearing process that encompasses a period of eight months for establishment of BPA new rate designs including new 2- and 5-year rates. The effective date for the establishment of new 2- and 5-year rates is October 1, 1996.

In order to have sufficient time to conduct a full rate proceeding for new 2- and 5-year rate proposals, BPA and most parties to the 1995 rate proceeding agreed that BPA would propose to extend BPA's current adjustable rates with a 4 percent surcharge for a 1-year period, October 1, 1995, through September 30, 1996. The extension of rates requires a separate expedited proceeding and procedural schedule.

After 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:

(1) The 1995 Wholesale Power and Transmission Rates Proceeding is designated WP–95/TR–95, and will be a 90-day expedited rate proceeding conducted pursuant to section 1010.10 of the Procedures Governing Bonneville Power Administration Rate Hearings, 51 FR 7611 (1986) (hereinafter Procedures). This proceeding will extend current rates with a surcharge and establish the 3rd AC, annual cost rate, and the Pacific Northwest Coordination Agreement (PNCA) rate.

(2) The March 22 Order also established a subsequent 8 month procedural 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 1996 Wholesale Power Proceeding is designated WP–96, and Transmission Rates Proceeding is designated TR–96 and both will be conducted pursuant to section 1010.9 of the Procedures.

(3) 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.

In the March 22 Order, the Hearing Officers ruled that after March 22, 1995, separate official records will be maintained and separate decisions will be issued for each of the three proceedings designated above. 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 above.

Finally, the Hearing Officers established the final rate case schedules for Docket Numbers WP–95/TR–95, WP–96/TR–96, and TC–96. The schedule established by the Hearing Officers for Docket Number WP–95/TR–95 provides an opportunity for interested persons to review BPA proposed rates, to participate in the rate hearing, and to submit oral and written comments. All comments and documents intended to become part of the Official Record in this process should contain the file number designation WP–95/TR–95. Consideration of comments may result in a final rate proposal differing from the rates proposed in this Notice.

II. Background

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.

On March 9, 1995, BPA published in the **Federal Register** a notice of availability of BPA's preliminary proposed Wholesale Power and Transmission Rate schedules, 60 FR 12915. Since that time, BPA has continued to study the adequacy of its preliminary rate proposal, including its proposal to tier rates for requirements service. On March 17, 1995, BPA and most parties to the 1995 rate proceedings agreed to a settlement whereby BPA would propose that current rates be extended for 1 year and surcharged 4 percent to meet BPA revenue requirements. 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. These representatives suggested that BPA's new Power Sales Contracts and new rate structures should be coordinated to allow customers to carefully consider the new rates and contracts package in detail before making any long-term commitments.

BPA's initial proposal for the 1995 rate case proposes to surcharge by 4 percent each component of its current adjustable rates, including a Variable Industrial Power (VI) rate extended through September 30, 1996, for 1 year, from October 1, 1995, through September 30, 1996.

III. Major Studies

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

A. Loads and Resources Study and Documentation
B. Revenue Requirement Study and Documentation
C. Revenue Forecast Study and Documentation
D. Section 7(b)(2) Rate Test Study and Documentation

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 direct service industry (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.

BPA's resource acquisition plans are based on work by BPA and the NPPC staff and reflect extensive input and review by the general public and the region's utilities. The specific resource acquisitions and associated costs included in this proposal are based on BPA's 1994 Draft Strategic Business Plan. Besides emphasizing a diverse resource portfolio, including both conservation and generating resources, BPA is committed to moving toward a blend of acquisition methods, including BPA-designed, utility-designed, and developer-initiated programs. This combination of resource diversity and acquisition approaches allows BPA to better deal with varying circumstances and uncertainties.

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 the Columbia River flow augmentation project and ''spill.'' For this proposal, a 50-year hydro study was completed, which includes assumptions regarding the Columbia River flow augmentation. The hydro study starts in August 1995. The 50-year study determines expected nonfirm energy availability for the region.

B. Revenue Requirement Study

The Bonneville 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. 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. Separate generation and transmission revenue requirements are developed in the Revenue Requirement Study. 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 1995 initial rate proposal is based on cost and revenue estimates for FY 1996. The cost estimates include an undistributed reduction of $80 million. This reflects BPA's decision to reduce revenue requirements by this amount to enable it to set rates at a level which recover its costs but also meet 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, and 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. It measures the financial risks surrounding the revenue and expense forecasts used to set rates. Results of the risk analysis are used to determine the amount of planned net revenue required for risk mitigation.

C. Revenue Forecast Study

The revenue forecast determines BPA's expected level of sales and revenue for the rate period, fiscal year 1996. Revenues are forecasted primarily by applying rates to a load forecast. In addition, because the load forecast assumes critical water, and streamflows usually are greater-than-critical, the revenue forecast reflects the effect of greater-than-critical streamflows (the product of which is secondary energy) on BPA's revenues. Secondary energy affects the revenue forecast by increasing or decreasing estimated revenues from the generating public utilities, direct-service industries, open market sales, and incidental wheeling. The revenue forecast is based on the average of 50 historical water years.

BPA prepares two types of revenue forecasts: (1) Revenues forecasted under current rates; and (2) revenues forecasted under proposed rates. The rates in effect since October 1993 are used in the calculation of forecasted revenues at current rates for the rate test period, fiscal year 1996. BPA also develops price forecasts for certain prices that are not set by the rate schedules to determine revenues under the Variable Industrial Power (VI) rate, for contractual sales of surplus firm power, for sales at the Nonfirm Energy rate, and for rates applicable to the WNP–1 and WNP–3 Exchange Agreements.

Included in the Revenue Forecast Study are the proposed wholesale power and transmission rate schedules, which are summarized below.

D. 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.

IV. Wholesale Power Rate Schedules and General Rate Schedule Provisions

Table of Contents

A. Introduction

The proposed wholesale power rate schedules are published as part of the Revenue Forecast Study. BPA agreed in the Settlement Agreement that its 1995 initial rate proposal would propose to apply a 4 percent surcharge to each component of its current adjustable rates, including the Variable Industrial Power (VI) rate which BPA would propose to extend through September 30, 1995. The current VI–91 rate expires June 30, 1996. BPA also agreed to propose that the surcharged rates would be effective for the period October 1, 1995, through September 30, 1996.

Consistent with the Settlement Agreement, BPA proposes to retain its current rate design, including most of the rate adjustments contained in the 1993 Wholesale Power Rate Schedules. BPA proposes to adjust each rate component contained in the Priority Firm Power (PF) rate, Industrial Firm Power (IP) rate, Variable Industrial Power (VI) rate, and New Resources (NR) rate such that the overall effective rate increase for sales under these rate schedules is 4 percent. BPA proposes to increase the demand and energy charges in these rates by 4 percent and also to increase by 4 percent the Irrigation Discount and First Quartile Discount. BPA proposes to increase the Energy Return Surcharge based on the changes in the PF demand charge.

BPA is proposing to retain the current percentages for the Low Density Discount and Availability Charge without further adjustments. Any change to these rate adjustments could result in an overall rate increase to customers different from 4 percent. In addition, BPA is proposing to maintain the Unauthorized Increase Charge at its current level. The Unauthorized Increase Charge is designed to deter customers from taking more power than they are entitled to take. The level of current Unauthorized Increase Charge achieves that purpose and as such a further increase is unnecessary.

BPA has some long-term contract rates that are tied to changes in BPA's PF rate. BPA is proposing to increase these rates by 4 percent. In addition, BPA has rates that depend on changes in BPA's Average System Cost (BASC). BPA also is proposing to increase BASC by 4 percent and consequently any rates that are based on changes in BASC also will be increased by 4 percent.

BPA also proposes to adjust the rate components contained in its Emergency Capacity (CE) rate and Nonfirm Energy rate schedules. Since the price BPA can obtain from these rates is based on market conditions, these rate schedules do not contain fixed rates but rather contain caps or ceilings. BPA proposes to increase the CE rate cap and the Intertie Charge by 4 percent. In the NF rate, BPA is proposing to increase the average cost of nonfirm energy, which triggers the Intertie adder charge, and retain the upper limit on its Standard nonfirm energy rate by 4 percent. Given current market conditions, increasing the cap on the NF Standard rate is not expected to result in increased revenues during the rate period. BPA also is proposing to increase the Intertie Charge and the NF Contract rate by 4 percent.

BPA is proposing to extend the Reserve Power (RP) rate, the Share-the-Savings (SS) rate and the Power Shortage (PS) rate unchanged for the 1 year period. These rates normally are not adjusted to reflect changes in BPA's costs. The RP rate is based on BPA's estimate of its long-term marginal cost. This rate has not been adjusted since 1987. The SS rate is an experimental nonfirm energy rate that allows for a mutually agreed-to formula rate. The PS rate is a contractually agreed-to rate and is available for sales under the Shortage Agreement. The parties to the Shortage Agreement recently agreed to extend that agreement for another year.

Unlike its other rates, BPA's current Surplus Power (SP–93) rate does not expire on September 30, 1995. FERC has approved the SP–93 rate through September 30, 1998. 67 FERC ¶ 61351 (June 20, 1994). Therefore, since the SP rate continues to be in effect during the 1-year rate period, BPA proposes to retain its current SP–93 rate and not refile a new SP rate for the 1-year rate period agreed to in the Settlement Agreement. The current SP–93 rate contains a contract rate and a flexible rate. BPA does not expect to make any sales at the contract rate during the rate period. The flexible rate is capped at BPA's highest cost resource, which is significantly above the expected market price during the rate period. As such increasing the SP flexible rate by 4 percent would not advance the settlement's cost recovery objectives.

B. Summary of Rate Schedules

A summary of the proposed 1995 Wholesale Power Rate Schedules is provided below. Each of the rate schedules includes sections specifying the customer class and the service available under the rate schedule, the rates for the sales offered under the schedule, the billing factors, other special provisions for rate adjustments, such discounts or penalties that apply to that rate schedule, and the cost basis of the rates in the schedule (resource contribution). Because the 1995 rates will be effective for a 1-year period, BPA is not proposing an Interim Rate Adjustment for these rates.

1. Priority Firm Power rate: The proposed Priority Firm Power (PF–95) rate schedule would replace the PF–93 rate schedule. Power is available under the PF–95 rate schedule to public bodies, cooperatives, Federal agencies, and utilities participating in the residential exchange under section 5(c) of the Northwest Power Act. Priority Firm power must be used to meet firm loads within the Pacific Northwest. The PF rate consists of diurnally differentiated demand charges and seasonally differentiated energy charges. Other rate adjustments include an Irrigation Discount, a Low Density Discount, an Energy Return Surcharge, Unauthorized Increase Charge, Conservation Surcharge, Outage Credit and Power Factor Adjustment.

2. New Resource Firm Power rate: The proposed New Resource Firm Power (NR–95) rate schedule would replace the NR–93 rate schedule. The NR–95 rate schedule is available to investor-owned utilities under net requirements contracts for resale to consumers, and to publicly owned utilities for New Large Single Loads. The NR rate consists of diurnally differentiated demand charges and seasonally differentiated energy charges. Other rate adjustments include an Irrigation Discount, a Low Density Discount, an Energy Return Surcharge, Unauthorized Increase Charge, Conservation Surcharge, Outage Credit and Power Factor Adjustment.

3. Industrial Firm Power rate: The proposed Industrial Firm Power Rate (IP–95) rate would replace the IP–93 rate. The IP–95 rate schedule is available to BPA's direct-service industrial customers for firm power to be used in their industrial operations. The IP rate consists of diurnally differentiated demand charges and seasonally differentiated energy charges. Other rate adjustments include a First Quartile Discount, Curtailment Charge, Unauthorized Increase Charge, Outage Credit and Power Factor Adjustment.

4. Variable Industrial Power rate: The Variable Industrial Power (VI–95) rate schedule is available to DSIs purchasing from BPA under the 1986 Variable Rate Contract. The proposed VI–95 rate schedule is unchanged from prior years other than to update the rates and rate parameters based on the rate adjustment criteria established in 1991 and the 1995 rate case. The proposed base rate components of the VI–95 rate include the 4 percent surcharge, as do the First Quartile Discount and the Lower and Upper Rate Limits. The Lower and Upper Pivot Aluminum Prices are those that were effective July 1, 1995, pursuant to the VI–91 rate. They will be adjusted again on July 1, 1996. The VI rate is proposed to be extended three months past its expiration date, June 30, 1996, so that its term will be consistent with the other rates proposed for fiscal year 1996. The term of the proposed VI–95 rate thus would be October 1, 1995, through September 30, 1996.

5. Special Industrial Power rate: The proposed Special Industrial Power (SI–95) rate would replace the SI–93 rate. The SI rate is available to any DSI purchaser which uses a raw mineral indigenous to the region as its primary resource and which qualifies for the special rate under the procedures established in section 7(d)(2) of the Northwest Power Act. The SI rate consists of diurnally differentiated demand charges and seasonally differentiated energy charges. Other rate adjustments include a Curtailment Charge, Unauthorized Increase Charge, Outage Credit, and Power Factor Adjustment.

6. Nonfirm Energy rate: The proposed Nonfirm Energy (NF–95) rate schedule replaces the NF–93 rate. The NF–95 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 NF–95 rate schedule includes four rate components: A flexible Standard rate, a flexible Market Expansion rate, a flexible Incremental rate, and a fixed Contract rate. Other adjustments include a Guaranteed Surcharge and an Intertie Charge. The NF Rate Cap continues to apply to all sales under the NF–95 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.

7. The Reserve Power rate: The Reserve Power (RP–95) rate schedule replaces the RP–93 rate schedule. The 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 rate consists of diurnally differentiated demand charges and a flat energy charge. Other rate adjustments include a Power Factor Adjustment.

8. The Power Shortage rate: The Power Shortage (PS–95) 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 PS–95 rate schedule unless specified by contract. The 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. Other rate adjustments include a Power Factor Adjustment.

C. Wholesale Power Rate Schedules

Schedule PF–95

Priority 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. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers for direct consumption, construction, test and startup, and station service.

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge

a. $4.307 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

b. No demand charge during Offpeak Period hours during a billing month.

2. Energy Charge

a. 23.06 mills per kilowatt-hour of billing energy for the billing months September through March.

b. 16.94 mills per kilowatt-hour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge

a. $4.307 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

b. No demand charge during Offpeak Period hours during a billing month.

2. Energy Charge

a. 23.06 mills per kilowatt-hour of billing energy for the billing months September through March.

b. 16.94 mills per kilowatt-hour of billing energy for the billing months April through August.

Section III. Billing Factors

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors ''a'' and ''b,'' below:

a. The lower of:

(1) The larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) The Measured Demand, before adjustment for power factor.

b. The lower of:

(1) The Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. For the months September through March, the sum of:

(1) 76 percent of the Measured Energy (excluding unauthorized increase); and

(2) 24 percent of the Computed Energy Maximum.

b. For the months April through August, the sum of:

(1) 63 percent of the Measured Energy (excluding unauthorized increase); and

(2) 37 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

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 Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

Section IV. Adjustments And Special Provisions

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.90 mills per kilowatt-hour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the LDD. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.6 of the GRSPs and subsequent to any other rate adjustments.

E. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

F. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during the billing months August through March.

b. 57.40 mills per kilowatt-hour during the billing months April through July.

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 during Peak Period hours, before adjustment for power factor, which 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:

(a) In accordance with the provisions of the ''Relief from Overrun'' exhibit to the power sales contract; or

(b) If such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) To a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) To a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month, shall be billed:

(a) In accordance with the provisions of the ''Relief from Overrun'' exhibit to the power sales contract; or

(b) As unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

G. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.5 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales 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 shall be subject to the following surcharge for each additional kilowatt-hour so returned:

1. 4.25 mills per kilowatt-hour for the months of April through October;

2. 1.80 mills per kilowatt-hour for the months of November through March.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF–95 rate is 72.2 percent FBS and 27.8 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule IP–95

Industrial Firm Power Rate

Section I. Availability

This schedule is available to direct service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule, the IP–95 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser's Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of First Quartile Service.

A. Demand Charge

1. $5.316 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 21.90 mills per kilowatt-hour of billing energy for the billing months September through March.
2. 18.02 mills per kilowatt-hour of billing energy for the billing months April through August.

Section III. Billing Factors

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the GRSPs. If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP–95 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the DSI power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), then BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatt-hours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI's load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

Section IV. Adjustments and Special Provisions

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.72 mills per kilowatt-hour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Unauthorized Increase

1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

D. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

E. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP–95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule VI–95

Variable Industrial Power Rate

Section I. Availability

This schedule is available to DSI customers for purchases under the Power Sales Contract implementing the VI rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power; and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated GRSPs in the Variable Rate Contract, DSIs electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive, for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Sales under this schedule are made subject to BPA's GRSPs.

Section II. Term of the Rate

This rate schedule shall take effect on October 1, 1995, and shall terminate at midnight September 30, 1996.

Section III. Rate

A. Base Rate

The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the Plateau Energy Charge.

1. Base Variable Industrial Rate

a. Demand Charge

$6.233 per kilowatt of billing demand, as adjusted, occurring during the Peak Period during a billing month. No demand charge is applied during Offpeak Period hours.

b. Plateau Energy Charge

18.83 mills per kilowatt-hour of billing energy, as adjusted.

2. First Quartile Service Discount

0.59 mills per kilowatt-hour of billing energy.

3. Lower Rate Limit

15.03 mills per kilowatt-hour of billing energy.

4. Upper Rate Limit

24.63 mills per kilowatt-hour of billing energy.

B. Base Rate Parameters Subject to Annual Adjustments

The following base rate parameters shall be used to determine power bills for DSI customers purchasing power under the Variable Rate Contract. These parameters will be adjusted July 1, 1996, in accordance with the procedures contained in section VII.B of the GRSPs.

1. Lower Pivot Aluminum Price

75.4 cents per pound.

2. Upper Pivot Aluminum Price

91.6 cents per pound.

Section IV. Formula

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.

A. Demand Charge

1. The Demand Charge, as stated in section III.A.1.a of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. Plateau Energy Charge

When the monthly billing aluminum price (described in section VII.A of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1 and III.B.2 of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b of this rate schedule.

2. Reductions to Plateau Energy Charge

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP-MAP) * (LS)

where:

LP=the Lower Pivot Aluminum Price as stated in section III.B.1 of this rate schedule.

MAP=the monthly billing aluminum price in cents per pound determined pursuant to section VII.A of the GRSPs

LS=lower slope=1 mill per kilowatt-hour
____
1 cent per pound

or

b. The Lower Rate Limit as stated in section III.A.3 of this rate schedule.

3. Increases to Plateau Energy Charge

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge+(MAP-UP) * (US)

where:

MAP=the monthly billing aluminum price in cents per pound, as determined according to section VII.A of the GRSPs.

UP=the Upper Pivot Aluminum Price as stated in section III.B.2 of this rate schedule.

US=upper slope=0.75 mills per kilowatt-hour
____
1 cent per pound

b. The Upper Rate Limit, as stated in section III.A.4 of this rate schedule.

Section V. Billing Factors

A. Billing Demand

1. Billing Demand for Customers Whose Entire BPA Load Is Served at the VI Rate

The billing demand for power purchased shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the GRSPs.

2. Billing Demand or Customers When Only a Portion of Their Total BPA Load Is Served at the Variable Rate

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

3. Billing Demand During Periods of Transitional Service

If BPA has agreed, pursuant to section 4 of the DSI power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), sections V.A.1 and V.A.2 of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatt-hours on which BPA assesses the charge for unauthorized increase.

Section VI. Other Adjustments and Special Provisions

A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1991, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B of the rate schedule shall be adjusted following the procedures set forth in section VII.B of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B of the rate schedule.

B. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus Firm Energy Load Carrying Capability (FELCC), a discount contained in section III.A.2 of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section VI.F of this rate schedule. To qualify for the First Quartile Discount, the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Rate Contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

C. Unauthorized Increase

1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during the billing months August through March.

b. 57.40 mills per kilowatt-hour during the billing months April through July.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

D. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the BPA Operating Level by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

E. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI to whom BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

Section VII. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the VI–95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule SI–95

Special Industrial Power Rate

Section I. Availability

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. Schedule SI–95 supersedes schedule SI–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Special Industrial Power Rate charges.

A. Demand Charge

1. $3.827 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 21.20 mills per kilowatt-hour of billing energy for the billing months September through March;

2. 15.08 mills per kilowatt-hour of billing energy for the billing months April through August.

Section III. Billing Factors

A. Billing Demand

The billing demand for power purchased under the Standard Special Industrial Power rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the GRSPs.

However, if BPA has agreed, pursuant to section 4 of the direct service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), BPA shall instead bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

B. Billing Energy

The billing energy under the Special Industrial rate shall be the Measured Energy for the billing month, minus any kilowatt-hours on which BPA assesses the charge for unauthorized increase.

Section IV. Adjustments and Special Provisions

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI's power sales contract. Any curtailment charge levied shall be computed using the Special Industrial Power rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

C. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Special Industrial Power rate, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The SI–95 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule CE–95

Emergency Capacity Rate

Section I. Availability

This schedule is available for the purchase of capacity provided the purchaser requests such capacity and BPA has determined that capacity is available for such purpose. This schedule is available when:

A. An emergency exists on the purchaser's system, or

B. The purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load.

This schedule supersedes Schedule CE–93 which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

Section II. Rate

A. Demand Charge

As mutually agreed by BPA and the purchaser, up to $0.321 per kilowatt of demand per calendar day or portion thereof.

B. Intertie Charge

The demand charge specified above shall be increased by $0.044 per kilowatt per day for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

Section III. Billing Factors

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar day. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such day, the billing demand for that day shall be the lower demand which BPA is able to supply.

Section IV. Billing Period

Bills shall be rendered monthly.

Section V. Special Provision

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

Section VI. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CE–95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.6 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 55.7 mills per kilowatt-hour.

Schedule NR–95

New Resource Firm Power Rate

Section I. Availability

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

A. Demand Charge

1. $5.357 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 28.66 mills per kilowatt-hour of billing energy for the billing months September through March.

2. 25.10 mills per kilowatt-hour of billing energy for the billing months April through August.

Section III. Billing Factors

In this section billing factors are listed for computed requirements purchasers (section III.A), metered requirements purchasers, and those purchasers not covered by section III.A (section III.B).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors ''a'' and ''b,'' below:

a. The lower of:

(1) The larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) The Measured Demand, before adjustment for power factor.

b. The lower of:

(1) The Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. For the months September through March, the sum of:

(1) 55 percent of the Measured Energy; and

(2) 45 percent of the Computed Energy Maximum.

b. For the months April through August, the sum of:

(1) 43 percent of the Measured Energy; and

(2) 57 percent of the Computed Energy Maximum.

B. Metered Requirements Purchasers and Other Purchasers Not Covered by Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE–2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

Section IV. Adjustments and Special Provisions

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.90 mills per kilowatt-hour, to the charges for qualifying energy purchased under this rate schedule. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

C. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.6 of the GRSPs and subsequent to any other rate adjustments.

D. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

2. Calculation of the Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) To a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) To a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour, shall be billed:

(a) In accordance with the provisions of the ''Relief from Overrun'' exhibit to the power sales contract; or

(b) If such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) To a class of power that BPA delivers during such month 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 month, shall be billed:

(a) In accordance with the provisions of the ''Relief from Overrun'' exhibit to the power sales contract, or

(b) As unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

E. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.5 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's billing demand and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatt-hour so returned:

1. 4.25 mills per kilowatt-hour for the months of April through October; and
2. 1.80 mills per kilowatt-hour for the months of November through March.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR–95 rate is 89.7 percent Exchange and 10.3 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule NF–95

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. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF–95 supersedes Schedule NF–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's GRSPs.

Section II. Rates

The average cost of nonfirm energy is 23.31 mills per kilowatt-hour. The NF–95 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 defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 27.97 mills per kilowatt-hour.

B. 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.

C. 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.

D. Contract Rate

The Contract rate is 14.83 mills per kilowatt-hour of billing energy.

Section III. Adjustments to Rates

A. Guaranteed Delivery Surcharge

A surcharge of 2.00 mills per kilowatt-hour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

The Intertie Charge, on rate offers under any of the rates specified above, for sales of nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie shall be:

1. Inapplicable for rate offers of less than 23.31 mills per kilowatt-hour;
2. At the discretion of BPA, from zero through 3.23 mills per kilowatt-hour, for rate offers of 23.31 mills per kilowatt-hour; or
3. 3.23 mills per kilowatt-hour, for rate offers greater than 23.31 mills per kilowatt-hour.

Section IV. Billing Factors

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

Section V. Application and Eligibility

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a 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 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 qualifying under section V.B.2 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 2.0 mills per kilowatt-hour.

Purchasers qualifying under section V.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 4.0 mills per kilowatt-hour.

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

Purchasers qualifying under section V.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 V.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 4.0 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 VI. 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 because of unexpected generation or transmission losses.

Section VII. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 92.7 percent FBS and 7.3 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule SS–95

Share-the-Savings Rate

Section I. Availability

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS–95 supersedes Schedule SS–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C of the GRSPs or lower than 1.00 mill per kilowatt-hour.

Section III. Billing Factor

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings rate contract.

Section IV. Application and Eligibility

A. General Requirements

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. Have executed a contract specifying application of the Share-the-Savings Rate Schedule, and
2. Have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable

purchase of electricity to qualify for this rate.

B. BPA Service Priority

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions set forth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The SS–95 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule PS–95

Power Shortage Rate

Section I. Availability

This schedule is available inside the Pacific Northwest for the purchase of Shortage Power to a utility when a shortage exists on its system and the utility requests Shortage Power under this rate schedule, or when Shortage Power is being delivered to a utility as the result of statewide or regionwide curtailment. This schedule is also available for sales under the Share-the-Shortage agreement, or a similar substitute agreement.

This rate schedule is also available inside the Pacific Northwest when BPA arranges for purchase energy at the request of a customer. BPA is not obligated to make Shortage Power available or broker power under this rate schedule unless specified by contract. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

Section II. Rates

A. Power Rate

The power rate is any offered rate not to exceed 100.00 mills per kilowatt-hour. 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

The billing factors shall be:

A. Power Purchases

The factors to be used in determining the billings for power purchases under this rate schedule are as follows:

1. Billing Demand

The billing demand shall be the Contract Demand as specified in the contract initiating such arrangement or as mutually agreed to by the parties. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

2. Billing Energy

The billing energy shall be the Contract Energy as specified in the contract initiating such arrangement or as mutually agreed to by the parties. Otherwise the billing energy shall be the Measured Energy.

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 amount of kilowatt-hours purchased.

Section IV. Adjustments and Special Provisions

A. Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for shortage power on metered amounts, when specified in this rate schedule or in the contracts, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Power Brokering

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.

C. Share-the-Shortage Transactions

In the event a Share-the-Shortage type agreement is executed, BPA may make shortage power available to participants under such agreement. Any transactions entered into by BPA pursuant to the Share-the-Shortage agreement shall be subject to the terms and conditions specified in that agreement. The PS–95 rate does not incorporate the agreement but the agreement controls if there is any conflict between the PS–95 rate and the agreement. The rate for transactions under the Share-the-Shortage agreement is any rate within the limits specified by the power rate but may not exceed the maximum rate specified in the agreement. The rate for Share-the-Shortage transactions is independent of any rate offered under this rate schedule for sales that do not fall under the agreement. The PS–95 power 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.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PS–95 rate is based upon the BPA's highest cost resource which currently is an FBS resource.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

Schedule RP–95

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–93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

Section II. Rate

A. Demand Charge

1. $3.640 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

25.30 mills per kilowatt-hour of billing energy.

Section III. Billing Factors

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

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 as adjusted for power factor.

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 Measured Energy.

Section IV. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

Section V. Resource Cost Contribution

BPA has made the following determinations:

A. The RP–95 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

D. General Rate Schedule Provisions (GRSPs)

Table of Contents

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

A. Approval of Rates

These 1995 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). BPA will request FERC approval effective October 1, 1995. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for 1 year: PF–95, IP–95, VI–95, SI–95, CE–95, NR–95, SS–95, NF–95, PS–95, and RP–95.

B. General Provisions

These 1995 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1993 rate schedules (which became effective October 1, 1993) 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 Northwest Power Act. All sales of power made 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, and the Northwest Power Act.

Section II. Types of BPA Service

A. 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 for direct consumption, construction, test and startup, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.)

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged.

Power purchased under the rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. New Resource Firm Power

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

1. For any New Large Single Load,
2. For firm power purchased by investor-owned utilities (IOUs) pursuant to power sales contracts with BPA, and

3. For construction, test and start-up, and station service for facilities owned or operated by IOUs.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct service industrial (DSI) purchaser pursuant to the DSI's power sales contract and subject to:

1. The restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and

2. The restrictions given in the Restriction of Deliveries section of the power sales contract.

D. Special Industrial Power

Special Industrial Power is electric power which BPA will make continuously available to any DSI that qualifies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI's load which is in excess of the DSI's Operating Demand for Industrial Firm Power or Special Industrial Power.

F. 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.

G. Surplus Firm Power

Surplus Firm Power is firm energy, firm power (firm energy with capacity), and firm capacity (capacity with energy return requirements) in excess of the amount required to meet BPA's existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy 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 mostly sold under the Nonfirm Energy rate schedule, NF–95. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS–95, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy 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.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

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

2. To provide service when no other type of power is deemed applicable; or

3. To serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

Section III. Billing Factors and Billing Adjustments

A. Billing Factors for Demand

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

(1) At each point of delivery for which the metered demand is the basis for determination of the Measured Demand,

(2) During each time period specified in the applicable rate schedule, and

(3) During any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

(1) Emergencies or breakdowns on, or maintenance of, the Federal system facilities; and

(2) Emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) To each system for which scheduled demand is the basis for determination of the Measured Demand;

(2) During each time period specified in the applicable rate schedule; and

(3) During any billing period. Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be 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. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate 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 which will be used to calculate the Ratchet Demand.

3. 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 power sales 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.''

4. Computed Peak Requirement

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.

5. Computed Average Energy Requirement

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.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. The 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.

7. Curtailed Demand

A Curtailed Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

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. 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 power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power rate schedule at the Standard Industrial rate. Auxiliary Power sales to DSIs electing to purchase under the Variable Industrial Power rate schedule (VI–95) shall be made at the rate determined pursuant to section III of the VI–95 rate schedule. Auxiliary Power sales to DSIs purchasing under the Special Industrial rate will be made only at the Standard Special Industrial Power rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special 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.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly BPA Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service 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 a level of service for the Offpeak Periods other than 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, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatt-hour of unauthorized increase associated with each 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, the Variable Industrial Power rate schedule, and the Standard rate under the Special Industrial 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.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereinafter defined.

a. 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 power sales contract, and delivered to a purchaser:

(1) At all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) During any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. 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:

(1) For each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) During any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy

The Contract Energy shall be the maximum number of kilowatt-hours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatt - hours}}{\sqrt{(\text{Kilowatt - hours})^2 + (\text{Reactive kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

When deliveries to a purchaser at any point of delivery either:

a. Include more than one class of power; or

b. Are provided under more than one rate schedule and it is impracticable to meter the kilowatt-hours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a low power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Outage Credit

To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA's inability to provide full service, provided such adjustment is mandated by the purchaser's power sales contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, 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:

(1) The purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) The average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such 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 data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) 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.

b. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) The purchaser must serve as an electric utility offering power for resale;

(2) The purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) The purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For Calendar Year (CY) 1995, the average Priority Firm Power rate shall be the average of the PF–93 Preference rate for 9 months and the PF–95 Preference rate for 3 months;

(4) The purchaser's kilowatt-hour-to-investment ratio (Ratio 3.a.(1)) must be less than 100;

(5) The purchaser's consumers-per-mile ratio (Ratio 3.a.(2)) must be less than 12; and

(6) The purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:

(a) The kilowatt-hour-to-investment ratio is equal to or greater than 25 but less than 35; or

(b) The consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:

(a) The kilowatt-hour-to-investment ratio is equal to or greater than 15 but less than 25; or

(b) The consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:

(a) The kilowatt-hour-to-investment ratio is less than 15; or

(b) The consumers-per-mile ratio is less than 3.

4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.90 mills per kilowatt-hour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the LDD, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts. However, if the purchaser also purchases energy from BPA for general requirements, and receives an irrigation discount on those purchases, a second irrigation discount will not be applied to that energy through the RPSA exchange. Therefore, the irrigation discount will not be applied to any portion of the purchaser's irrigation sales qualifying for the RPSA exchange that receives the discount as a general requirements purchase.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA regional office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA regional office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA regional offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred. Irrigation reports to BPA shall include the following monthly information for the reporting period:

(1) Utility name and period for which the report is being made;

(2) Total irrigation sales and total qualifying irrigation energy sales (in kilowatt-hours) by month;

(3) Total qualifying irrigation sales (in kilowatt-hours) by month under 400 horsepower, for exchanging utilities;

(4) Total utility firm system requirements for other than full requirement customers by month (in kilowatt-hours);

(5) Total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatt-hours; and

(6) The Purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bimonthly, or seasonally. If the Purchaser is an exchanging utility, the Purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it chooses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Coincidental Billing

Purchasers of Priority Firm Power and New Resource Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See Special Provisions Exhibits of the Power Sales Contract, GCP E 17.

6. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF and NR rate schedules are subject to the Conservation Surcharge. If only 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 power purchases multiplied by: (a) The portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sunday.

Section IV. Other Definitions

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

1. 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

2. 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.

C. 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 nonfirm energy, including any applicable service charges or rate adjustment, 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 Notification of the NF Rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3 of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BPA's Average System Cost (BASC) at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the period 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 + .30(DEC − BASC)

Where:

BASC=BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 29.41 mills per kilowatt-hour.

DEC=The Decremental Fuel Cost as determined in accordance with section IV.C.5 of these GRSPs.

4. Determination of BASC

For purposes of determining BASC, the following definition shall apply:

a. BPA's total system costs shall be 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 shall be the sum of all BPA's system firm and nonfirm 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 Decremental Fuel Cost

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. The monthly decremental fuel cost shall be:

a. the sum of:

(1) The average California price for gas determined by multiplying the monthly gas use (WGU) developed pursuant to section IV.C.8.a times the monthly California gas price (MGP) determined pursuant to section IV.C.6 rounded to the nearest tenth of a mill; and

(2) The average California price for petroleum determined by multiplying the monthly petroleum use (WOU) developed pursuant to section IV.C.8.b times the monthly California petroleum price (MOP) determined pursuant to section IV.C.7 rounded to the nearest tenth of a mill.

b. Divided by the sum of the WGU and WOU developed in sections IV.C.8.a and b, respectively, rounded to the nearest tenth of a mill.

6. California Gas Price

The MGP for purposes of calculating the decremental cost component of the rate cap shall be based on the following formula:

$$MGP = \frac{AGP * HGP}{10}$$

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. Prices shall be rounded to the nearest one-tenth of a cent.

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:

a. 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;

b. 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

c. Dividing the average monthly California gas price in a. above, by the average monthly California gas price in b. 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.

7. California Petroleum Price

The MOP for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MOP = \frac{AOP * HOP}{10}$$

Where:

AOP=the last available average oil price for California electric utility plants expressed in cents per million Btu reported in EPM published by the EIA, U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HOP=the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:

a. Summing all California petroleum 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 petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent;

b. Summing all California petroleum 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 petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent; and

c. Dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10=the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatt-hour.

8. Weighting Factors

For purposes of determining California fuel prices for the month, gas and petroleum prices will be weighted based on California's historical use of these two alternative fuels.

a. Historical Gas Use in California. The following formula shall be used to determine the weighting factor for gas prices (WGU):

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 consumptions 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:

(1) 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;

(2) 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

(3) Dividing the average consumption of gas in California for the month t as determined in (1) above by the average consumption of gas for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum Use in California. The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

WOU=COU*HOU

Where:

COU=the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of EPM published by the EIA, U.S. Department of Energy.

HOU=the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month t) and the month for which petroleum consumption is reported in EPM (month r) using the following procedures:

(1) Summing the reported net-petroleum 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 petroleum consumption was reported and rounded to the nearest gigawatthour;

(2) Summing the reported net-petroleum 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 petroleum consumption was reported and rounded to the nearest gigawatthour; and

(3) Dividing the average consumption of petroleum in California for the month t as determined in (1) above by the average consumption of petroleum for the month r or as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of BPA's Average System Cost

For purposes of determining BASC, the following definitions shall apply:

1. BPA's total system costs shall be 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.

2. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted in 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.

Section V. Application of Rates Under Special Circumstances

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF–95, and Emergency Capacity rate schedule, CE–95, for any electric energy or capacity which has been supplied:

1. For use during an emergency on the purchaser's system, or

2. Following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

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

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

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

2. 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.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period—Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. Utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. Determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or

b. Bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. Suspended,
2. Interrupted,
3. Interfered with,
4. Curtailed, or
5. Restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

Section VI. Billing Information

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose actual firm load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. The NLSL demand during BPA's diurnal capacity billing periods,
2. The NLSL energy during BPA's energy billing periods, and
3. The NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the *purchaser's* billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.

F. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228–6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by Financial Services and updated as necessary.

1. Computation of Bills

Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's financial services group.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the *specified customer* beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Section VII. Variable Industrial Rate Parameters and Adjustments

A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price

The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by ''*Metals Week*,'' in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price

BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly billing aluminum price to be used for billing purposes. Upon written request supporting documentation shall be provided.

3. Changes in Aluminum Price Indicators

In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. 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 methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1991, and every July 1, thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B of the rate schedule, shall be subject to change for billing purposes as herein described. The term ''annual adjustment date'' shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1991 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA's revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determination and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, those parties that submitted comments, and parties that requested notification, of the final determination.

2. Annual Adjustment Procedures

a. Annual Adjustment of the Lower Pivot Aluminum Price

Beginning with the July 1, 1991, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

b. Annual Adjustment of the Upper Pivot Aluminum Price

For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the midpoint between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(1) (2)*(AAP)–ALP:

where

AAP=the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.

ALP=the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.

(2) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(3) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. Cost Escalators

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) Electricity Cost Index

The average VI rate in mills per kilowatt-hour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatt-hour (the average VI–86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 0.944 (the value of the GNP Implicit Price Deflator for 1985 with 1987=1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:

Electricity Cost Index	.30
Labor Cost Index	.20
Alumina Cost Index	.20
Other Costs Index	.30

c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:

Electricity Cost Index	.25
Other Costs Index	.75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the VI rate has been in effect beginning August 1986. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the VI rate has been in effect beginning August 1986, shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year's dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred. Each price shall be rounded to the nearest tenth of a cent.

V. Transmission Rate Schedules And General Transmission Rate Schedule Provisions (GTRSPs)

Table Of Contents

A. Summary of Rate Schedules

BPA is proposing to surcharge by 4 percent the following transmission rate schedules: Formula Power Transmission; Integration of Resources; Southern Intertie Transmission; Northern Intertie Transmission; Eastern Intertie Transmission; and Energy Transmission. Pursuant to the Settlement Agreement, BPA proposes to increase the components of the FPT 95.3 rate by 4 percent for the October 1, 1995–September 30, 1996 period. The increase to this rate for the 1-year period, however, does not preclude BPA from increasing the 3-year FPT rate, as necessary, in its 1996 rate case. BPA also is proposing extension of the Market Transmission (MT) rate, Use of Facilities (UFT) rate, and Townsend-Garrison Transmission (TGT) rate with no changes. The MT rate was developed for use among Western Systems Power Pool (WSPP) participants to allow for flexible hourly, daily, weekly, and monthly charges. The UFT and TGT rate schedules are formula 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.

In addition, BPA is proposing the Southern Intertie Annual Costs (AC–95) rate to be applied to owners of Pacific Northwest (PNW) Alternating Current (AC) Intertie capacity. This rate recovers the capacity owner's pro-rata share of actual PNW AC Intertie costs: operations, maintenance, general plant, and other identified expenses, as well as capital costs of replacements and reinforcements. The proposed AC–95 rate takes the place of the AC–93 rate, which was a ''bridge'' rate until Capacity Ownership contracts were complete. Copies of the Ownership Agreement are available for examination at BPA's Public Information Center at the address listed at the beginning of this notice.

B. Transmission Rate Schedules

Schedule FPT–95.1

Formula Power Transmission

Section I. Availability

This schedule supersedes schedule FPT–93.1 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 electric power and energy using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System (FCRTS). This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions (GTRSPs).

Section II. Rate

A. 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.

1. 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:

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0386 per mile

b. Main Grid Interconnection Terminal Factor: $0.28

c. Main Grid Terminal Factor: $0.46

d. Main Grid Miscellaneous Facilities Factor: $1.96

2. 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:

a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.2895 per mile

b. Secondary System Transformation Factor: $4.26

c. Secondary System Intermediate Terminal Factor: $1.34

d. Secondary System Interconnection Terminal Factor: $0.71

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A. 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:

1. During months for which service is specified, the monthly charge defined in Section II.A., and

2. During other months, the monthly charge defined in Section II.A. multiplied by 0.2.

Section III. Billing Factors

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. The Transmission Demand;
B. The highest hourly Scheduled Demand for the month; or
C. The Ratchet Demand.

Schedule FPT–95.3

Formula Power Transmission

Section I. Availability

This schedule supersedes schedule FPT–91.3 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 3 years. It is available for firm transmission of electric power and energy 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 availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

Section II. Rate

A. 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.

1. 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:

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0292 per mile
b. Main Grid Interconnection Terminal Factor: $0.28
c. Main Grid Terminal Factor: $0.31
d. Main Grid Miscellaneous Facilities Factor: $1.36

2. 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:
a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.2039 per mile
b. Secondary System Transformation Factor: $2.63
c. Secondary System Intermediate Terminal Factor: $0.87
d. Secondary System Interconnection Terminal Factor: $0.46

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A. 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 charge shall be:
1. During months for which service is specified, the monthly charge defined in Section II.A., and
2. During other months, the monthly charge defined in Section II.A. multiplied by 0.2.

Section III. Billing Factors

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:
A. The Transmission Demand;
B. The highest hourly Scheduled Demand for the month; or
C. The Ratchet Demand.

Schedule IR–95

Integration of Resources

Section I. Availability

This schedule supersedes IR–93 and is available for firm transmission service for electric power and energy using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. The definitions of Main Grid and Secondary Systems are the same as for the FPT–95.1 and FPT–95.3 rate schedules and are contained in the General Transmission Rate Schedule Provisions (GTRSPs). For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's GTRSPs.

Section II. Rate

The monthly charge shall be the sum of A and B where:

A. Demand Charge

1. $0.441 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 * transmission distance/75)] * ($0.441 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. Energy Charge

1.10 mills per kilowatthour of billing energy.

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 nonfirm transmission rate (currently ET–95), 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. Billing Demand

The billing demand shall be the largest of:

1. The Transmission Demand, except under General Transmission Agreements where a Total Transmission Demand is defined;

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

3. The Ratchet Demand.

B. Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

Schedule IS–95

Southern Intertie Transmission

Section I. Availability

This schedule supersedes IS–93 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

Section II. Rate

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.23 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.734 per kilowatt per month of billing demand and 1.76 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

Section III. Billing Factors

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity.
The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.
B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

Schedule IN–95

Northern Intertie Transmission

Section I. Availability

This schedule supersedes IN–93 and is available for all transmission on the Northern Intertie pursuant to an Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for transmission of non-BPA power on the Northern Intertie shall be 0.89 mills per kilowatthour.

Section III. Billing Factors

Billing Energy

The billing energy shall be the monthly sum of the scheduled kilowatthours.

Schedule IE–95

Eastern Intertie Transmission

Section I. Availability

This schedule supersedes IE–93 and is available for all nonfirm transmission on the Eastern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for nonfirm transmission on the Eastern Intertie shall be 2.12 mills per kilowatthour.

Section III. Billing Factors

Billing Energy

The billing energy shall be the monthly sum of the scheduled kilowatthours.

Schedule ET–95

Energy Transmission

Section I. Availability

This schedule supersedes ET–93, unless otherwise specified in the Agreement, with respect to delivery using Federal Columbia River Transmission System facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie, and is available for firm (of not more than 1 year duration) or nonfirm transmission between points within the Pacific Northwest. BPA may interrupt nonfirm service which is provided under this rate schedule. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for transmission of non-BPA power shall be 2.10 mills per kilowatthour.

Section III. Billing Factors

Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

Schedule MT–95

Market Transmission

Section I. Availability

This schedule supersedes MT–91 and is available for Transmission Service for transactions using Federal Columbia River Transmission System facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. General Transmission Rate Schedule Provisions.

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 kilowatthour 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.

Schedule UFT–95

Use-of-Facilities Transmission

Section I. Availability

This schedule supersedes UFT–83 unless otherwise provided in the Agreement, and is available for firm transmission over specified Federal Columbia River Transmission System facilities. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

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:

$$\frac{A}{D}$$

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 TGT–95

Townsend-Garrison Transmission

Section I. Availability

This schedule supersedes TGT–1 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 Transmission Rate Schedule Provisions.

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:

$$\text{Intertie Charge} = [((\text{TAC}/12) - \text{NFR}) \times \frac{(\text{CR} - \text{EC})}{\text{TCR}}]$$

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 Pub. L. 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.

Schedule AC–95

Southern Intertie Annual Costs Rate and Billing Provisions

Section I. Availability

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule are subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

Section II. Rate

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''Operations Cost'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''Maintenance Cost'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\text{MOP} = \frac{\text{AOP} * \text{HOP}}{10}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''General Plant Cost'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''Other Costs'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''Contracts and Rates Costs'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''Power Scheduling Costs'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge equals:

$$\frac{\text{End of Term Costs * Capacity Ownership Percentage}}{\text{Months}}$$

Where

''Months'' is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

''End of Term Costs'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals: Replacement Cost * Capacity Ownership Percentage.

2. For each Reinforcement, the charge equals: Reinforcement Cost * Capacity Ownership Percentage.

Where

''Replacement Cost'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

''Reinforcement Cost'' means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

''Capacity Ownership Percentage'' is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

Section III. Adjustments

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A–G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A–G shall be adjusted, and payment or refund made with interest, pursuant to paragraph 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains. A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A–G during the fiscal year that such Operating Plan is effective.

Annual Costs Rate

Billing Provisions

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the annual costs rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II. Billing Information

Payment of Bills

Charges pursuant to the annual costs rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228–6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

A. Computation of Bills

1. Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

2. Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

3. Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

B. Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

C. Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

D. Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

E. Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5) of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

F. Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or because of an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

1. If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

2. If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

C. General Transmission Rate Schedule Provisions (GTRSPs)

Table of Contents

Section I. Adoption of Revised Transmission Rate Schedules and General Transmission Rate Schedule Provisions (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1995.

B. General Provisions

These 1995 Transmission Rate Schedules and associated GTRSPs supersede BPA's 1993 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1993) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be 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, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102–486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

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

Section II. Billing Factor Definitions and Billing Adjustments

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

Section III. Other Definitions

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the 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, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist 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; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

Section IV. Billing Information

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228–6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

V. Charges Under The Amended and Integrated Pacific Northwest Coordination Agreement

The Pacific Northwest Coordination Agreement (PNCA) is an agreement for planned operations among the utilities and other entities that operate the major electric generating facilities and systems in the Pacific Northwest. The parties jointly and cooperatively plan and coordinate their combined generation facilities so as to produce the optimum firm load carrying capability (FLCC) of the coordinated system. FLCC is the firm load that could be carried under coordinated operation with critical streamflow conditions and with the use of all reservoir storage.

In order to coordinate operations, and so that each party can meet its individual FLCC, the PNCA provides for exchanges of energy and capacity among the parties. The agreement sets up charges for each form of exchange. The parties are negotiating a successor agreement to the PNCA, and have agreed on charges to apply under the new agreement.

All terms contained herein have the meaning accorded them in the Amended and Integrated Pacific Northwest Coordination Agreement. These rates are to be effective on the date on which rates are effective under the Amended and Integrated Pacific Northwest Coordination Agreement, as provided in such Agreement. They will remain in effect until revised rates are approved.

A. Interchange Energy Imbalances

1. Initial Deliveries of Interchange Energy

$$\text{Energy Charge} = \frac{(\text{heat rate} * \text{fuel price})}{1{,}000} + \text{adder}$$

Heat rate = 10,000 BTU/kWh

Fuel price = Average mainline interruptible or spot market natural gas price at Sumas, Washington, in $/MMBTU (dollars per million BTUs), for the twelve months ending the immediately preceding June 30, as published in *Inside FERC*, or, in the event that *Inside FERC* is no longer published, a similar replacement publication.

Adder = 4.75 mills/kWh, adjusted each August 1 beginning August 1, 1997, by the change in the Consumer Price Index (for all urban consumers as published by the Bureau of Labor Statistics) for Portland, Oregon, for the twelve-month period ending the immediately preceding June 30.

2. Return of Interchange Energy

The Energy Charge for Return of Interchange Energy shall be the charge in effect for initial deliveries of Interchange Energy at the time the energy being delivered as Return of Interchange Energy was delivered as an initial delivery of Interchange Energy.

B. Interchange Energy Service Charge

1. No charge for energy returned between 7:00 a.m. and 10:00 p.m., Monday through Saturday.

2. 2.50 mills per kilowatthour of energy returned at other hours, unless such energy was supplied during such other hours, or its return during such other hours was requested, in either of which events there shall be no charge.

C. Interchange Capacity Imbalances

$2.00 per kilowatt week of demand.

D. Transfers Due to Forced Outage

1. Transfer Due to Loss of Thermal Capability

$2.00 per kilowatt week of demand plus the greater of (a) the charge for Interchange Energy Imbalances and (b) the incremental costs of operating the resource used to supply the requested energy plus an adder of 4.00 mills per kilowatthour. The adder shall be adjusted each August 1 beginning August 1, 1997 by the change in the Consumer Price Index (for all urban consumers as published by the Bureau of Labor Statistics) for Portland, Oregon, for the twelve-month period ending the immediately preceding June 30.

2. Transfer of Emergency Capacity

$2.00 per kilowatt week of demand plus the greater of (a) the charge for Interchange Energy Imbalances and (b) the incremental costs of operating the resource used to supply the requested energy. In the event that BPA requires the receiving party to return the energy associated with the transfer of emergency capacity, only the demand charge shall apply.

E. Holding Interchange Energy Service Charge

1. Basic Charge

2.00 mills per kilowatthour of Holding Interchange Energy on delivery to BPA and 1.50 mills per kilowatthour of Holding Interchange Energy on return from BPA (3.50 mills per kilowatthour total). A loss of Holding Interchange Energy because of spill will result in a refund of 2.00 mills per kilowatthour of Holding Interchange Energy that is converted to Stored Energy and spilled.

2. Reshaping Charge

2.50 mills per kilowatthour of energy. This charge shall apply, in each Light Load Hour during which the energy delivered or returned is greater than the average hourly amount of energy delivered or returned that day, to the amount of energy delivered or returned during such hour that exceeds the daily hourly average. This charge applies in addition to the basic charge.

F. Stored Energy Service Charge

For the purposes of this rate, light load hours and heavy load hours shall not include any hours designated by the reservoir party as peak load hours.

1. Charges Paid on Delivery of Energy to a Reservoir Party

a. 2.00 mills per kilowatthour of energy delivered to BPA on Light Load Hours.
b. 1.00 mill per kilowatthour of energy delivered to BPA on Heavy Load Hours.
c. No charge for energy delivered to BPA on Peak Load Hours.

2. Charges Paid on Return of Energy Stored Less Than Two Weeks

a. 1.00 mill per kilowatthour of energy returned from BPA on Light Load Hours.
b. 3.50 mills per kilowatthour for energy returned from BPA on Heavy Load Hours.
c. 5.00 mills per kilowatthour for energy returned from BPA on Peak Load Hours.

3. Charges Paid on Return of Energy Stored for Two Weeks or More

a. No charge for energy returned from BPA on Light Load Hours.
b. 2.50 mills per kilowatthour for energy returned from BPA on Heavy Load Hours.
c. 4.00 mills per kilowatthour for energy returned from BPA on Peak Load Hours.

4. Charges Paid on Return of Energy in Cases of Imminent Spill

a. No charge for energy returned from BPA on Light Load Hours.
b. 2.50 mills per kilowatthour for energy returned from BPA on Heavy Load Hours.
c. 2.50 mills per kilowatthour for energy returned from BPA on Peak Load Hours.

5. Refund of Storage Charges in Cases of Spill

In the event that stored energy is not returned to a party because of spill on BPA's system, or in the event that BPA transfers the stored energy to another Reservoir Party to avoid spill and the transferred energy is later spilled, BPA will refund the charges paid under section F.1. in an amount equal to the charges paid under such section, divided by the kilowatthours of energy delivered to BPA, multiplied by the kilowatthours of stored energy that is spilled.

G. Transfers To Avoid Spill

1. No charge for stored energy transferred by a Reservoir Party to BPA in order to avoid spill.
2. The applicable Stored Energy Service charge shall apply in the event that BPA accepts the transfer of stored energy to avoid spill and then returns the stored energy to the original delivering party.

H. Transmission Service Charges

In any energy or capacity transaction that utilizes BPA transmission facilities where BPA acts solely as a transferor the following charges shall apply to both delivery and return of the energy, if applicable:
1. 1.60 mills per kilowatthour of Interchange Energy or Generation Impact Replacement Energy paid by the receiving party.
2. 1.75 mills per kilowatthour of Holding Interchange and Storage Energy paid by the party requesting the return.
3. No charge for In Lieu Energy, except when the supplying or receiving

party requires BPA, under the terms of the PNCA, to provide transmission, in which case the charge shall be 2.00 mills per kilowatthour of In Lieu Energy paid by the party requiring BPA to provide such transmission.

4. 2.00 mills per kilowatthour of Provisional Energy paid by the Reservoir Party.

5. 2.00 mills per kilowatthour of energy associated with Transfers Due to Cross-Border Flow Deviations paid by the party receiving the transfer.

6. 2.00 mills per kilowatthour of energy associated with Interchange Capacity and FOR Capacity paid by the party requesting the delivery.

I. Special Storage Arrangements

1. Suggested Rate

a. 1.00 mills per kilowatthour for energy returned during Light Load Hours.

b. 3.00 mills per kilowatthour for energy returned during other hours.

2. Flexible Rate

The charges for special storage arrangements may be specified at a higher rate as mutually agreed between the party requesting the special storage arrangement and BPA.

Issued in Portland, Oregon, on April 17, 1995.

Randall W. Hardy,

Administrator and Chief Executive Officer.

[FR Doc. 95–10065 Filed 4–28–95; 8:45 am]

BILLING CODE 6450–01–P

Federal Energy Regulatory Commission

[Docket No. ER95–727–000, et al.]

PacifiCorp, et al.; Electric Rate and Corporate Regulation Filings

April 24, 1995.

Take notice that the following filings have been made with the Commission:

1. PacifiCorp

[Docket No. ER95–727–000]

Take notice that on April 10, 1995, PacifiCorp tendered for filing an amendment in the above-referenced docket.

Copies of this filing were supplied to AES Power Inc., Engelhard Power Marketing, Inc. InterCoast Energy Marketing Company, Gulfstream Energy, LLC, the Washington Utilities and Transportation Commission and the Public Utility Commission of Oregon.

Comment date: May 8, 1995, in accordance with Standard Paragraph (E) at the end of this notice.

2. PacifiCorp

[Docket No. ER95–728–000]

Take notice that on April 10, 1995, PacifiCorp tendered for filing an amendment in the above-referenced docket.

Copies of this filing were supplied to Bountiful, Rainbow, InterCoast, the Washington Utilities and Transportation Commission and the Public Utility Commission of Oregon.

Comment date: May 8, 1995, in accordance with Standard Paragraph (E) at the end of this notice.

3. C.C. Pace Energy Services

[Docket No. ER94–1181–003]

Take notice that on April 5, 1995 C.C. Pace Energy Services (C.C. Pace) filed certain information as required by the Commission's July 25, 1994, letter order in Docket No. ER94–1181–000. Copies of C.C. Pace's informational filing are on file with the Commission and are available for public inspection.

4. NorAm Energy Services Inc.

[Docket No. ER94–1247–004]

Take notice that on April 14, 1995, NorAm Energy Services, Inc. tendered for filing its quarterly report in the above-referenced docket reporting the following transactions:

1. Cajun Electric purchased from NES, 50 MWh at $21.00, non-firm energy, delivered to the Cajun/Entergy interconnect.

2. Associated Electric Coop. purchased from NES, 1600 Mwh at $17.00, non-firm energy, delivered to Associated Electric/TVA interconnect.

3. Associated Electric purchased from NES, 800 Mwh at $23.00, non-firm entergy, delivered to Associated Electric/Entergy interconnect.

4. Central Illinois Public Service sold to NES, 54 Mwh at $16.50, non-firm energy, delivered to CIPS/TVA interconnect.

5. Louisville Gas & Electric sold to NES, 1648 Mwh at $15.50, non-firm energy, delivered to LG&E/TVA interconnect.

6. Cajun Electric Co-op sold to NES, 824 Mwh at $19.00, non-firm energy, delivered to Cajun/Entergy interconnect.

5. American Power Exchange, Inc Inc.

[Docket No. ER94–1578–002]

Take notice that on April 17, 1995, American Power Exchange, Inc. tendered for filing its quarterly report in the above-referenced docket reporting no purchases or sales of electricity in the quarter ending March 31, 1995.

6. Wickland Power Services

[Docket No. ER95–300–001]

Take notice that on April 14, 1995, Wickland Power Services, tendered for filing its quarterly report in the above-referenced docket, reporting no purchases or sales of electricity in the quarter ending March 31, 1995.

7. South Eastern Energy Resources, Inc.

[Docket No. ER95–385–001]

Take notice that on April 17, 1995, South Eastern Energy Resources, Inc. tendered for filing its quarterly report in the above-referenced docket reporting no purchases or sales of electricity in the quarter ending March 31, 1995.

8. Consolidated Edison Company of New York, Inc.

[Docket No. ER95–509–000]

Take notice that on April 17, 1995, Consolidated Edison Company of New York, Inc. (Con Edison), tendered for filing revised proposed supplements to its Rate Schedules FERC No. 96 and FERC No. 92.

The revised proposed Supplement No. 7 to Rate Schedule FERC No. 96 applicable to electric delivery service to public customers and to non-public, economic development customers of the New York Power Authority (NYPA), and the revised proposed Supplement No. 4 to Rate Schedule FERC No. 92, applicable to electric delivery service to commercial and industrial economic development customers of the County of Westchester Public Service Agency (COWPUSA) and the New York City Public Utility Service (NYCPUS), set forth the terms of a settlement agreement under which Con Edison's base rates and charges for these services will neither increase nor decrease during the 12-month period ending March 31, 1996. The settlement agreement also provides that changes in rates for these services will be implemented for the 12-month periods ending March 31, 1997 and March 31, 1998, with the possibility of additional limited changes in these rates in succeeding annual periods.

These supplements would supersede proposed Supplement No. 6 and Supplement No. 7 to Rate Schedule FERC No. 96 and proposed Supplement No. 4 to Rate Schedule FERC No. 92 which Con Edison tendered to the Commission on January 30, 1995. These supplements have never been made effective and should be deemed superseded upon grant of the relief requested in the present filing.

A copy of this filing has been served on NYPA, COWPUSA, NYCPUS, and