BPA'S 1996

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER AND TRANSMISSION RATES

INDEX

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1996 wholesale power and transmission rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). Bonneville Power Administration (BPA) has requested that FERC make these rates and GRSPs effective on October 1, 1996, for customers who are billed by BPA on a calendar month basis and on the first day of the first billing month following that date for all other customers. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These 1996 wholesale power and transmission rate schedules and the GRSPs associated with these schedules supersede BPA's 1995 rate schedules (which became effective October 1, 1995) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 1996 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

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

C. Notices

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

D. Late Payment Provisions

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

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

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Ancillary Services Rate Discount

BPA may offer discounted rates for ancillary services available under the APS rate schedule and for Load Regulation, which also is available under the PF, IP and NR rate schedules. Discounts may be offered to reflect cost variations or to match rates available from a third party, consistent with FERC policy, *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule,* 61 Fed. Reg. 21,540 (1996), FERC Stats & Regs. ¶ 31,036 (1996) (FERC Order 888). Discounts shall be posted on the Open Access Same-Time Information System (OASIS) and will be implemented consistent with the Standards of Conduct.

B. Calculated Energy Capacity

Calculated Energy Capacity (CEC) is the amount of energy load (aMW) that a DSI could consume at a particular separately metered facility when that facility is operating at full capacity. It is the billing factor for DSI Load Shaping. BPA determines CEC for each separately metered facility based on historical DSI energy use and changes in plant technology. A separately metered facility may be an entire plant when there is only one BPA meter at that plant, or it may be a portion of a plant when there are multiple BPA metering points to that plant. BPA will revise the CEC for a particular separately metered facility on an as-needed basis, as any of the factors used in its calculation changes. BPA will provide the CEC to be applied during an Annual Billing Cycle to the customer in writing 30 days prior to the start of the cycle.

C. Conservation Surcharge (PF/NR only)

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

D. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.14 mills per kilowatthour.

2. The approximate cost contribution of different resource categories to each rate schedule is as follows:

Rate Schedule	*Resource Cost Contribution*		
	Federal Base System	**Exchange**	**New Resources**
PF-96	83.95%	16.05%	0%
IP-96	0%	94.70%	5.30%
NR-96	0%	94.70%	5.30%
FPS-96	0%	94.70%	5.30%

E. Curtailment Charge (IP only)

Curtailment charges are charges assessed for power and transmission demand charges pursuant to section 9 of a DSI's 1981 Contract for failure to purchase an amount of power equal to 75 percent of the DSI's Operating Demand.

F. Delivery Charge

Transmission customers taking service under the PTP, NT, and NTP rate schedules and transmission customers increasing their firm service under the IR rate shall pay a Delivery Charge for service over Utility and DSI Delivery Facilities.

1. Delivery Charges

a. DSI

Service over DSI Delivery facilities is charged at the Use-of-Facilities rate.

b. Utility

For service over Utility Delivery facilities (i.e., service at voltages below 34.5 kV), the charge is $0.750 per kilowatt per month.

2. Utility Delivery Charge Billing Factors

The billing factor for transmission customers taking service under the PTP and NT rate schedules and for increases in firm service under the IR rate is specified in section 2.a., below. The billing factor for NTP customers, with the exception of Computed Requirements Customers (CRCs) under certain conditions, is also shown in section 2.a, below. The billing factor in section 2.a. applies to CRCs who, during Heavy Load Hours (HLHs), do not purchase power under 1981 Contracts. The billing factor for CRCs under the NTP rate schedule who purchase power under 1981 contracts during HLHs is specified in section 2.b., below.

a. All Transmission Customers Except Computed Requirements Customers Who Do Not Purchase Power Under 1981 Contracts During HLHs

The monthly billing demand for the charge specified in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as Utility Delivery facilities.

b. Computed Requirements Customers Who Purchase Power Under 1981 Contracts During HLHs

The monthly billing demand for the charge specified in section 1.b. shall be the total load at the Points of Delivery specified as Utility Delivery facilities that occurs on the hour of the highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the customer's PODs. For CRCs who do not waive CMR, this is the same hour that is determined by the NTP Base charge billing factor.

3. Other Provisions

a. Metering Adjustment

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand under section 2.a. shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.74.

b. Utility Delivery Charge Billing Factor Adjustment

The monthly Utility Delivery billing factors in section 2 shall be adjusted for customers who pay for Utility Delivery facilities under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

G. Deviation Adjustment

The Deviation Adjustment applies to Partial Requirements Purchasers and may apply to Full Requirements Purchasers under the 1996 Contract.

1. Monthly Application of Deviation Adjustment

Deviation is the difference between the quantity of power that was actually taken from BPA (Measured Energy) and the quantity the customer is entitled to receive under its Contract Obligation. If a customer's Measured Energy exceeds its Contract Obligation, the deviation is a positive deviation. If its Measured Energy is less than its Contract Obligation, the deviation is negative. The customer is allowed a limited amount of deviation from its Contract Obligation without incurring an Unauthorized Increase Charge or an adjustment for take-or-pay obligations; this Authorized Deviation is specified in the customer's power sales contract. When the customer's deviation for an hour, day, or month exceeds the limit allowed under the contract, the excess deviation is unauthorized. Unauthorized Negative Deviations are treated as take-or-pay amounts, added to the Measured Energy, and billed at the appropriate rate. Unauthorized Positive Deviations are subtracted from the Measured Energy and billed at the Unauthorized Increase Charge.

2. Annual Application of the Deviation Adjustment

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

a. Rate Period Excess Purchases

If, at the end of each Annual Billing Cycle, BPA determines that the Purchaser has taken more power under the PF, IP, or NR rate than its actual Total Retail Load or Total Plant Load for the previous year, then the Purchaser shall be subject to the Unauthorized Increase Charge for all such excess purchases. This power shall be treated as an Unauthorized Positive Deviation, subtracted from the Measured Energy for the last month or months of the Annual Billing Cycle, and billed at the Unauthorized Increase Charge.

b. Unreturned Diverted Power

If, at the end of each Annual Billing Cycle, the Purchaser has not taken return of all of its Diverted Power for the year, then the Purchaser shall be subject to the Unauthorized Increase Charge for all Diverted Power that was not returned to the Purchaser's system during the year. This power shall be treated as an Unauthorized Positive Deviation, subtracted from the Measured Energy for the last month or months of the Annual Billing Cycle, and billed at the Unauthorized Increase Charge.

H. Energy Return Surcharge (PF/NR/FPS only)

Any purchaser:

1. who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the 1981 Contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that Purchaser's Billing Demand and Computed Average Energy Requirement for the billing month, or

2. who purchases capacity under the FPS rate schedule and returns more than 60 percent of its Contract Demand for the billing month during a single offpeak hour, and is subject to the Energy Return Surcharge

shall be subject to the following charge for each additional kilowatthour so returned:

- 2.44 mills per kilowatthour for the months of September - December;
- 2.42 mills per kilowatthour for the months of January - March;
- 3.27 mills per kilowatthour for the month of April;
- 3.79 mills per kilowatthour for the months of May - June;
- 4.11 mills per kilowatthour for the month of July;
- 4.91 mills per kilowatthour for the month of August.

FPS purchasers are subject to the Energy Return Surcharge stated above unless their agreement with BPA specifically provides otherwise.

I. Guaranteed Delivery Charge (NF only)

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

J. Local Stability Reserves Adjustment (IP/IPG/VI only)

A credit of 1.48 mills per kilowatthour shall be applied to the Purchaser’s Billing Energy for any customer that provides local stability reserves pursuant to the Bellingham Area Load Tripping Scheme. No credit shall be applied to those purchases subject to unauthorized increase charges.

K. Low Density Discount (PF/NR only)

1. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power (excluding transmission services) purchased under the PF and NR rate schedules by eligible purchasers as defined in section 2, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year.

a. <u>The KWh/Investment Ratio</u>

The KWh/Investment (K/I) ratio is calculated by dividing the Purchaser's total electric energy requirements during the previous calendar year by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of such year. The Purchaser's total electric energy requirements include firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses. For the 5-year rate period, the Purchaser's total electric energy requirements exclude the 1996 calendar year level of nonfirm sales to nonfirm retail loads. Nonfirm energy load is electric load that is subject to interruptions or curtailment on short notice at any time for any condition, including economic and physical conditions such as power shortages and transmission limitations. The Purchaser will report nonfirm sales to nonfirm retail loads for the period January 1, 1996, through December 31, 1996, to BPA by June 30, 1997. This 1996 level of nonfirm sales to nonfirm retail loads will not be included in calculations of the K/I ratio for the 5-year rate period. Beginning January 1, 1997, however, amounts of nonfirm sales to nonfirm retail loads above the 1996 level will be included to calculate the Purchaser’s K/I ratio.

b. <u>The Consumers/Mile of Line Ratio</u>

The Consumers/Mile of Line (C/M) ratio is calculated by dividing the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding the average number of consumers associated with separately billed services for water heating, electric space heating, and security lights) during the previous calendar year by the average number of pole miles of distribution line for such year, calculated by halving the sum of the end-of-year pole mile figures for the previous year and the current year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on average annual data provided in the Purchaser's financial and operating reports that they submit periodically to BPA (usually monthly or quarterly). In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the Pacific Northwest and, for Purchasers with service territories that include any areas outside the Pacific Northwest, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the Pacific Northwest and on the Purchaser's entire electric utility system inside and outside the Pacific Northwest. BPA will apply the eligibility criteria and discount percentages to the Purchaser's system within the Pacific Northwest and, where applicable, also to its entire system inside and outside the Pacific Northwest. The Purchaser's eligibility for the LDD will be determined by the lesser amount of discount applicable to its Pacific Northwest system or to its combined system inside and outside the Pacific Northwest. BPA, in its sole discretion, may waive the requirement to submit separate data for the customer with a small amount of its system outside the Pacific Northwest. Results of the calculations shall not be rounded. Retroactive billing for the LDD may be required if the data are not available by the January billing date.

Customers who have not provided BPA with all four requisite pieces of annual data (see 1.a. and 1.b, above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. LDDs issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the Purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

2. Eligibility Criteria

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

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

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

c. the Purchaser's average retail rate for the reporting year must exceed the average applicable Priority Firm Power rate for the qualifying period by at least 10 percent. For Calendar Year (CY) 1996, the average Priority Firm Power rate shall be the average of the PF-95 Preference rate for 9 months and the PF-96 Preference rate for 3 months. For CY 1997, the average Priority Firm Power rate shall be the PF-96 Preference rate;

d. the Purchaser's K/I ratio (Ratio 1.a) must be less than 100;

e. the Purchaser's C/M ratio (Ratio 1.b) must be less than 12; and

f. the Purchaser must qualify for a discount based on the criteria in section 3, below.

3. Discounts

The Purchaser shall be awarded the lesser of the following discounts beginning October 1, 1996, which for any year shall not differ from the Purchaser’s previous year’s discount by more than one-half of one percent (see below):

a. 7 percent, or

b. the sum, not to exceed 7 percent, of the two potential discounts for which the Purchaser qualifies, based on the following table:

LDD Percentage Discount Table

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
0.0%	$35.0 \le X$	$12.0 \le X$
0.5%	$31.5 \le X < 35.0$	$10.8 \le X < 12.0$
1.0%	$28.0 \le X < 31.5$	$9.6 \le X < 10.8$
1.5%	$24.5 \le X < 28.0$	$8.4 \le X < 9.6$
2.0%	$21.0 \le X < 24.5$	$7.2 \le X < 8.4$
2.5%	$17.5 \le X < 21.0$	$6.0 \le X < 7.2$
3.0%	$14.0 \le X < 17.5$	$4.8 \le X < 6.0$
3.5%	$10.5 \le X < 14.0$	$3.6 \le X < 4.8$
4.0%	$7.0 \le X < 10.5$	$2.4 \le X < 3.6$
4.5%	$3.5 \le X < 7.0$	$1.2 \le X < 2.4$
5.0%	$X < 3.5$	$X < 1.2$

4. LDD Phase-In Adjustment

If the Purchaser satisfies eligibility criteria 2.a.-2.e, above, and the discount calculated above differs from the existing discount by more than ½ of 1 percent, the applicable discount will be:

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

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

The foregoing formula will be applied each successive Fiscal Year until the then-current calculated discount is fully phased in.

If the Purchaser fails to satisfy eligibility criteria 2.a.-2.e. above, the applicable discount will be zero.

5. Additional Adjustment for Very Low Densities

If a Purchaser's C/M ratio is 3 or less and its K/I ratio is 26 or less, *after* determination of the discount pursuant to sections 3 and 4 above, an additional ½ percent shall be added to the Purchaser's discount, but the total discount shall not exceed 7 percent. In subsequent years, the ½ percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

L. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for BPA's nonfirm energy, including any applicable service charges or rate adjustments, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on a formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Customer Notification of the Value of the NF Rate Cap

Prior to the beginning of each calendar month, BPA shall determine the effective NF Rate Cap for that month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. This notification requirement does not apply if BPA does not intend to offer Nonfirm Energy at prices above BPA's Average System Cost (BASC) at any time during a month. BPA shall give the notification to the purchasers at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap is expected to apply. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the 12-year period that the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + [0.30 * (DEC - BASC)]

where:

BASC = BPA's Average System Cost
DEC = The Decremental Fuel Cost

4. Determination of BPA’s Average System Cost (BASC)

BPA’s Average System Cost is calculated by dividing BPA’s Total System Costs by BPA’s Total Annual System Sales, where:

a. *BPA's Total System Costs* are the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. *BPA's Total Annual System Sales* are the sum of all BPA's system firm and nonfirm energy sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each 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. For this rate period BASC has been determined to be 27.11 mills per kilowatthour.

5. Determination of the Decremental Fuel Cost (DEC)

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. All quantities are to be rounded to the nearest tenth of a mill in making the calculation.

The monthly decremental fuel cost shall be calculated using the following formula:

DEC = [(MGP * WGU) + (MOP * WOU)] / (WGU + WOU)

where:

MGP	=	the monthly California gas price
WGU	=	historical gas use in California
MOP	=	the monthly California petroleum price
WOU	=	historical petroleum use in California

a. Determination of MGP, the Monthly California Gas Price

MGP = AGP * HGP / 10

where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

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

i. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which MGPs were reported and rounded to the nearest one-tenth of a cent;

ii. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which MGPs were reported and rounded to the nearest one-tenth of a cent; and

iii. dividing the average monthly California gas price in “i” above, by the average monthly California gas price in “ii” above, and rounding to the nearest one-tenth, or three significant places.

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

b. <u>Determination of WGU, Historical Gas Use in California</u>

WGU = CGU * HGU

where:

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

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

i. summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour;

ii. summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour; and

iii. dividing the average consumption of gas in California for the month t as determined in "i" above by the average consumption of gas for the month r as determined in "ii" above and rounding to the nearest one-tenth, or three significant places.

c. Determination of MOP, the Monthly California Petroleum Price

MOP = AOP * HOP / 10

where:

AOP = same as AGP except the input data is for the average petroleum price (as opposed to the gas price).

HOP = same as HGP, except the data is for the petroleum price (as opposed to the gas price).

10 = the same conversion factor as used for converting the gas data.

d. Determination of WOU, Historical Petroleum Use in California

WOU = COU * HOU

where:

COU = the same as CGU except the data for monthly net petroleum-fired generation is used instead of the gas data.

HOU = the same as HGU, except the data for petroleum consumption is used instead of the gas data.

6. Changes in Data Sources

In the event that the data used to compute the NF Rate Cap become unavailable, BPA may identify and substitute other data sources for the purpose of calculating the monthly NF Rate Cap. As a result of this data substitution, it also may be necessary to modify the NF Rate Cap methodology to achieve an NF Rate Cap that is substantially equivalent in rate level to that which would have resulted from continued use of the data described in section 5, above.

BPA shall notify interested parties of its intent to substitute data sources or to substitute data sources and change the NF Rate Cap methodology at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason(s) for the proposed changes and describe its proposed alternative. Interested persons will have until close of business three weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final data sources and the final NF Rate Cap methodology to differ from BPA's initial proposal. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month in which the new NF Rate Cap parameters (data sources/methodology) become effective.

M. Operating Reserves Adjustment (IP/IPG/VI only)

The energy charges stated in the IP-96 rate schedules reflect a 2.73 mills per kilowatthour credit for the operating reserves a DSI provides to BPA pursuant to its power sales contract. If a DSI chooses not to provide operating reserves, a billing adjustment will be made to remove the effect of the credit.

N. Phase-In Mitigation

The phase-in mitigation is available for Full or Metered Requirements Preference customers. Phase-in mitigation does not apply to PF power purchased under a Residential Purchase and Sale Agreement or an Exchange Transmission Credit Agreement.

1. Eligibility Criteria

To qualify for the phase-in mitigation, a purchaser must:

a. be a Full Requirements customer of BPA as designated in the 1996 Contract, or a Metered Requirements customer of BPA as designated in the 1981 Contract;

b. agree to purchase all power from BPA for 5 years under one or more of BPA's 5-year rate schedules; and

c. have a rate increase greater than 9 percent for all BPA purchases, rounded to the nearest one-tenth of a percent, based on the determination in section 2 below.

2. Determination of Rate Increase for Phase-In Mitigation

The percentage rate increase faced by a Full or Metered Requirements purchaser will be calculated as follows:

a. Apply all applicable 1993 rate schedule (PF, NR, etc.) charges to the individual customer's FY 1997 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

b. Apply all applicable 1996 rate schedule (PF, NR, transmission, etc.) charges to the individual customer's FY 1997 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

c. If the value of 2.b minus the value of 2.a, divided by 2.a, is greater than 9 percent, rounded to the nearest tenth of a percent, the customer may notify BPA by letter to their Account Executive to phase in the 1996 rate increase. Such notice must be received by BPA by September 1, 1996. Purchasers may not apply for mitigation after that time.

3. Rate Adjustment

If the purchaser meets the eligibility criteria and requests BPA to phase in its 1996 rate increase, beginning October 1 of each year BPA will limit the monthly increase in the customer's bill to 9 percent in the first year, with additional 9-percent increments in each subsequent year over the effective period of the 1996 5-year rates.

The adjustment will be based on the difference between: (1) the purchaser's total monthly payment assuming the 1993 rates for the billing month were applied to power purchases for that month; and (2) the purchaser's total monthly payment under the 1996 rates for that month. In the first year, if the difference between the two is equal to or less than 9 percent, no adjustment will be made to the purchaser's monthly bill. If the difference between the two is greater than 9 percent, an adjustment will be made such that the monthly bill to that customer will reflect an increase equal to 9 percent. In subsequent years, no adjustment shall be made if the difference between (1) and (2) above is less than or equal to 18 percent in the second year, 27 percent in the third year, 36 percent in the fourth year, and 45 percent in the fifth year.

O. Reactive Power Charge

1. Description of the Reactive Power Charge

A Purchaser that purchases power under BPA's wholesale power rate schedules or transmission service on the Federal Columbia River Transmission System (FCRTS) under BPA's transmission rate schedules shall be charged for its Reactive Power requirements for such power or transmission service as described in this section, unless otherwise specified in an agreement existing prior to October 1, 1995.

The Reactive Power Charge replaces the Power Factor Adjustment provision included in BPA's 1995 wholesale power rate schedules. Purchasers previously granted Power Factor Adjustment waivers under BPA's prior wholesale power rate schedules shall be subject to the Reactive Power Charge.

If a Purchaser is taking delivery of real power at a point of delivery or point of integration under multiple rate schedules, the Purchaser will pay for its Reactive Power requirements at that point as if it is taking delivery under only one rate schedule. Each point of integration and point of delivery shall be monitored and billed independently for determining the Purchaser's total Reactive Power requirements and all associated billing factors, including the Reactive Deadband.

The charges for a Purchaser's Reactive Power requirements under this subsection shall be subject to the provisions of BPA's Billing Procedures.

2. The Purchaser's Reactive Power Requirements

The Purchaser's Reactive Power requirements shall be measured at each point of delivery and at each point of interconnection where the metered real power (MW) flow is unidirectional and the Purchaser is taking delivery of real power, either Federal or non-Federal. For points of interconnection, the metered real power flow must be unidirectional on all hours during the billing month.

3. Conditions for Application of the Reactive Power Charge

a. <u>Measured Data</u>

The Reactive Power Charge will apply to only the Purchaser's Reactive Power requirements for which measured data exist.

b. <u>Purchaser's Generating Resource Connected to the FCRTS</u>

The Reactive Power Charge shall apply to points of integration where a Purchaser's generating resource is directly connected to the FCRTS, *unless* the Purchaser's generating resource is either:

i. a synchronous generator equipped with a voltage regulator, or

ii. equipped with Reactive Power control devices that comply with BPA's applicable interconnection standards.

Such resource must actively support the voltage schedule at the point of integration at all times when the resource is in service, as determined by BPA, for this exemption to apply. Generating resources that do not satisfy the above criteria shall not be exempt from the Reactive Power Charge.

c. <u>Bidirectional Real Power Flow</u>

The Reactive Energy Charge will *not* be applied, and no new Ratchet Demand for Reactive Power will be established, at a specific point if the metered real power (on an hourly integrated basis) flows from the Purchaser's system to the FCRTS at that point for as little as one hour during the billing period. However, the Purchaser will still pay any previously incurred demand ratchet charges. The direction of the real power flow will be determined based on metered quantities, not on scheduled quantities.

d. Service by Transfer

Points of delivery that are served by transfer over another utility's transmission system will not be subject to the Reactive Power Charge unless (1) the transferor imposes a reactive power charge on BPA for serving such Purchaser's load or (2) there are BPA Network facilities between the Purchaser's points of delivery and the transferor's system.

e. Specific Points Exempt from the Reactive Power Charge

The Reactive Power Charge will *not* apply to the following points:

Nevada-Oregon Border (NOB)
Big Eddy 500kV
Big Eddy 230kV
John Day 500kV
Malin 500kV
Captain Jack 500kV
Garrison 500kV
Townsend 500kV

f. Special Circumstances

The Purchaser may submit requests to BPA for consideration of unique circumstances. BPA will evaluate the request and may make arrangements with the Purchaser to address the special circumstances.

4. Rate

BPA will bill the Purchaser for Reactive Power at each point each month as follows:

a. Reactive Demand

$0.08 per kVAr of lagging reactive demand in excess of the Reactive Deadband during HLH in all months of the year.

$0.06 per kVAr of leading reactive demand in excess of the Reactive Deadband during LLH in all months of the year.

No charge for leading reactive demand during HLH.

No charge for lagging reactive demand during LLH.

b. Reactive Energy

0.53 mills per kVArh for all lagging reactive energy in excess of the Reactive Deadband during all HLH of all months of the year.

0.53 mills per kVArh for all leading reactive energy in excess of the Reactive Deadband during all LLH of all months of the year.

No charge for leading reactive energy during HLH.

No charge for lagging reactive energy during LLH.

5. Billing Factors

a. Reactive Deadband

The Reactive Deadband (measured in kVAr) is used to determine the Reactive Billing Demand, Reactive Billing Energy, and Ratchet Demand for Reactive Power.

The Reactive Deadband for the billing periods commencing with the effective date of this provision through September 30, 1999, is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 33 percent (equivalent to a 0.95 power factor). The Reactive Deadband for each billing period after September 30, 1999, is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 25 percent (equivalent to a 0.97 power factor).

The Reactive Deadband for either HLH or LLH:

i. is computed once per billing period,

ii. does not vary during the billing period,

iii. is based on the maximum hourly integrated metered real power demand during that billing period, and

iv. is applied to both reactive demand and reactive energy.

b. Reactive Billing Demand

The Purchaser's Reactive Billing Demand shall be calculated independently for lagging Reactive Power and leading Reactive Power at each point for which a Reactive Power Charge is assessed.

All reactive demands shall be established in the particular Peak Period (HLH) or Offpeak Period (LLH) hour at each point during which the Purchaser's maximum applicable reactive demand is placed on BPA, regardless of the time of the real power peak at each point.

All reactive demand at each point shall be established on a non-coincidental basis, regardless of whether the Purchaser is billed for real power or transmission at such point on a coincidental or non-coincidental basis, *unless* otherwise specified in the agreement between BPA and the Purchaser, *or* coincidental billing is, in BPA's sole determination, more practical for BPA.

There will be separate reactive demands for lagging (HLH) and leading (LLH) demands. The Purchaser's Reactive Billing Demand for each point for the billing month shall be the *larger* of:

i. the largest measured reactive demand in excess of the Reactive Deadband during the billing period, *or*

ii. the Ratchet Demand for Reactive Power.

The Ratchet Demand for Reactive Power is equal to 100 percent of the largest measured reactive demand in excess of the Reactive Deadband during the preceding 2-year, 11-month period. The Ratchet Demand for Reactive Power for the 2-year, 11-month period preceding October 1, 1996, will be set at zero. Each point shall have a separate Ratchet Demand for lagging (HLH) and leading (LLH) reactive demand.

c. Reactive Billing Energy

The Purchaser's Reactive Billing Energy at each point shall be the sum of the hourly integrated metered reactive energy, in excess of the Reactive Deadband, delivered at such point during the billing period. (This quantity is the sum of the absolute values in excess of the Reactive Deadband, *not* the net value created by summing the positive/lagging reactive energy and the negative/leading reactive energy.)

6. Additional Adjustments

a. Resetting of the Ratchet Demand

BPA shall reset the Ratchet Demand to zero for either the HLH or LLH period for the Purchaser's Reactive Power for any point of delivery or point of interconnection if BPA determines that the following criterion is met:

The Purchaser has reduced its Reactive Power demand to 25 percent or less of its real power demand (i.e. has maintained at least a 0.97 power factor) at such point on all hours, in the respective diurnal period (HLH or LLH), for a 12-month continuous period following the setting of the ratchet.

b. Adjustment for Reactive Losses

Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand and Reactive Billing Energy.

P. Reservation Fee for Transmission Capacity

1. Conditions for Application of Reservation Fee

The Reservation Fee is available to customers who enter into an agreement for firm transmission service and want to postpone taking such service until a later date. The Reservation Fee will reserve transmission capacity for one year. A transmission customer can request yearly extensions up to a total reservation period of five (5) years. If during the reservation period, another customer requests service which can only be satisfied out of the reserved capacity, then the customer with the reservation must agree to pay the full monthly charge for the firm transmission service. Payment of the full charge becomes effective on the date when service under the competing request was to become effective. In the event the customer with the reservation elects to release the reserved capacity, the Reservation Fees paid for the current and past years will be forfeited.

2. **Reservation Fee**

The Reservation Fee shall be a nonrefundable fee equal to one month's charge for firm transmission service for each year or fraction of a year in which the customer chooses to postpone service. The Reservation Fee shall be paid in a lump sum within 30 days of the date the agreement is executed, and, for yearly extensions, within 30 days of the beginning of the extension. The Reservation Fee shall be assessed annually until transmission service begins or the reservation period ends, whichever occurs first. The Reservation Fee shall be specified in the executed agreement for transmission service.

3. **Billing Factors**

The billing factors shall be the same as the type of transmission service requested, as determined pursuant to the applicable transmission rate schedule.

Q. Transitional Service--Application of Rates During Initial Operation Period

Under the 1981 Contract, and as specified in BPA's Billing Procedures, BPA may agree to bill the purchaser for Transitional Service. Transitional Service shall apply to DSIs having new, additional or reactivated plant facilities, and utility purchasers serving industrial purchasers with power purchased from BPA. Transitional Service will not be available under the 1996 Contract.

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the kilowatt Billing Demand for the billing month shall be based on one of the following billing methods, as agreed to by BPA and the purchaser, based on load characteristics and consistent with the procedures outlined in BPA's Billing Procedures. If for any reason agreement is not reached on a billing method, #1 below shall serve as a default billing method. Reactive power will continue to be billed normally.

1. <u>Weighted Monthly Average of Daily Billing Demand</u>

The Billing Demand for each day is the maximum metered amount for any hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

2. Weighted Monthly Average of Daily HLH Billing Demand

The Billing Demand for each day is the maximum metered amount for any HLH hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

R. Unauthorized Increase Charge

If specified in the applicable rate schedule, BPA shall apply the charge for Unauthorized Increase to any purchaser taking demand and energy in excess of its contractual entitlement.

1. Charge for Unauthorized Increase

a. Demand Charge: Demand Charge from applicable power rate schedule.

b. Energy Charge: 100 mills per kWh in all months of the year.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an Unauthorized Increase. BPA shall apply the amount of Unauthorized Increase related to demand and the amount of Unauthorized Increase for energy to each hour of integrated or scheduled demand unless otherwise specified in the purchaser's contract.

a. Unauthorized Increase in Demand

That portion of any Measured Demand that exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

1. to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser;

2. to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour; or

3. to an authorized deviation or allowable increase in service (specified in the 1996 Contract) from the purchaser's Contract Obligation,

shall be billed:

1. in accordance with the provisions of the "Relief from Overrun" exhibit to the 1981 Contract; or

2. at the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the Purchaser's power sales contract.

b. Unauthorized Increase in Energy

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

1. to a class of power BPA delivers during such month pursuant to contracts between BPA and the purchaser;

2. to a type of power the purchaser acquires from sources other than BPA and which BPA delivers during such month; or

3. to an authorized deviation or allowable increase in service (specified in the 1996 Contract) from the purchaser's Contract Obligation,

shall be billed:

1. in accordance with the provisions of the "Relief from Overrun" exhibit to the 1981 Contract; or

2. at the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

c. Application of Annual Deviation Adjustments

Amounts of Measured Energy that are identified as Rate Period Excess Purchases, or Unreturned Diverted Power, shall be billed at the Unauthorized Increase Charge during the last month or months of the Annual Billing Cycle.

S. Utility Factor

For utility purchasers under the 1981 Contract with no Industrial Exemption, charges for Full Load Shaping and Load Regulation are multiplied by a utility-specific, annual Utility Factor. For utility purchasers under the 1981 Contract who select an Industrial Exemption, the Full Load Shaping charge is multiplied by an Adjusted Utility Factor that is calculated monthly. An Industrial Exemption does not affect the Utility Factor for Load Regulation.

The Utility Factors to be used for billing will be developed annually based on historical data provided by the customers to BPA. Previous calendar year data (January 1-December 31) will be used to develop a Utility Factor that will be in effect for the following fiscal year (October 1 - September 30). The customer shall submit its end of calendar year Financial and Operating Report and Generation Report (if applicable). BPA will develop a customer's Utility Factor once it has received all necessary data from the customer (usually in April). If a customer has not submitted the required data by June 1, BPA will prepare an estimate of the customer's historical annual Total Retail Load for the previous calendar year, after consultation with the customer, and prepare the Utility Factor from that estimate. Completed Utility Factors will be provided to the customers. The first effective year for Utility Factors coincides with the first year of implementation of the new rate structure: October 1, 1996-September 30, 1997. Historical data from the previous calendar year (January 1, 1995-December 31, 1995) will be used to develop the Utility Factor for this first year.

The Load Shaping and Load Regulation Utility Factors are calculated alike, with the exception that for the Utility Factor applied to Full Load Shaping and the Adjusted Utility Factor, New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract are excluded from the calculation of Total Retail Load. For each Metered Requirements customer, the utility factor calculation uses the customer's annual historical BPA purchases as the divisor. For each Actual Computed Requirements customer, the Utility Factor calculation uses the customer's annual historical Computed Energy Maximum as the divisor. Utility Factors are calculated as follows:

Load Regulation

For Metered Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load for the previous calendar year ÷ BPA energy purchases for the previous calendar year. The result of this calculation is capped at 6.

For Computed Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load for the previous calendar year ÷ Computed Energy Maximum for the previous calendar year. The result of this calculation is capped at 6.

Full Load Shaping

For Metered Requirements Customers:

The Utility Factor for the applicable fiscal year = customer Total Retail Load, excluding New Large Single Loads served by dedicated resources pursuant to section 8(e) of the 1981 Contract, for the previous calendar year ÷ BPA energy purchases for the previous calendar year. The result of this calculation is capped at 6.

For Computed Requirements Customers:

The Utility Factor for the applicable fiscal year = customer Total Retail Load, excluding New Large Single Loads served by dedicated resources pursuant to section 8(e) of the 1981 Contract, for the previous calendar year ÷ Computed Energy Maximum for the previous calendar year. The result of this calculation is capped at 6.

Full Load Shaping with an Industrial Exemption (Adjusted Utility Factor)

For Metered Requirements Customers:

The Adjusted Utility Factor for the month =
(one-twelfth of the customer's previous calendar year Total Retail Load, excluding New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract, minus the Industrial Exemption load forecast for the current month) ÷ (one-twelfth of the customer's BPA purchases for the previous calendar year minus the Industrial Exemption load forecast for the current month).

For Computed Requirements Customers:

The Adjusted Utility Factor for the month =
(one-twelfth of the customer's previous calendar year Total Retail Load, excluding New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract, minus the Industrial Exemption load forecast for the current month) ÷ (one-twelfth of the customer's total Computed Energy Maximum for the previous calendar year minus the Industrial Exemption load forecast for the current month).

SECTION III. DEFINITIONS

A. Products and Services Offered by BPA

1. Ancillary Services

Ancillary Services are those services necessary to support the transmission of electric power from resources to load while maintaining reliable operation of the FCRTS. Ancillary services include: Energy Imbalance, Control Area Reserves for Resources, Control Area Reserves for Interruptible Purchases, Load Regulation, and Transmission Losses. Ancillary services are available under the APS-96 rate schedule.

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

Power for the purpose of *Construction, Test and Start-Up, and Station Service* for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power, New Resources Firm Power, and Firm Power Products and Services rate schedules.

Construction, test and start-up, and station service power must be used in the manner specified below:

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

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

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

d. Power sold for construction, test and startup, and station service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

3. Control Area Reserves for Resources

Control Area Reserves for Resources are the control area services necessary to back up generation located in BPA's control area. Control Area Reserves for Resources provides the generation following needs and operating reserves obligations required for the generation in BPA's control area or by the transmission provider for the remainder of the delivery hour.

4. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are the non-spinning operating reserve obligations provided by BPA for interruptible energy delivered to BPA's control area. Interruptible energy is defined as energy deliveries that can be interrupted by the delivering control area or transmission provider during the delivery hour.

5. Control Area Services

Control Area Services are services that BPA provides to the Purchaser for real-time fluctuations in loads and resources during the delivery hour. With these services, BPA will deliver power in amounts that change automatically in response to changes in loads or resource output located in BPA's control area. These services meet the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP) for regulating margin and spinning and non-spinning operating reserves. In addition, BPA also may provide similar services to loads and resources outside BPA's control area. The general category, Control Area Services, includes:

a. Control Area Reserves for Resources;

b. Control Area Reserves for Interruptible Purchases;

c. Load Regulation;

d. Eccentric Load Following;

e. Supplemental Control Area Services

f. Interconnected Operation Services

g Other control area services.

6. DSI Non-Take-or-Pay Option

Purchase of the *DSI Non-Take-or-Pay Option* allows a DSI customer, for a fee, to purchase power under the IP rate without a take-or-pay obligation. To purchase this product, the Purchaser must have signed a 1996 Contract for specified amounts of non-take-or-pay load. The charge for this product is assessed per kilowatthour of the Purchaser's Billing Energy.

7. Eccentric Load Following

Eccentric Load Following provides instantaneous (second-to-second) regulation of firm power supply for a Purchaser's actual real-time eccentric load within the hour. An eccentric load is defined as any specific cyclic customer or consumer load with the ability to change periodically more than 50 MW in level at a rate of greater than 50 MW per minute, regardless of the duration of this change. Eccentric Load Following is included in Load Regulation service.

8. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with transmission to a load located in BPA's control area or from a generation resource located within BPA's control area. BPA allows an hourly Energy Imbalance Band of +/- 1.5 percent of the scheduled transaction (with a required minimum band of +/- one megawatt) to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transactions.

> *Positive Deviation* occurs on any hour when BPA delivers more energy to the Receiving Party at the Point of Delivery than BPA receives from the Delivering Party at the Point of Integration.
>
> *Negative Deviation* occurs on any hour when BPA receives more energy from the Delivering Party at the Point of Integration than BPA delivers to the Receiving Party at the Point of Delivery.

Energy Imbalance applies only to Points of Integration and/or Points of Delivery associated with generation resources and loads located within BPA's control area. Energy imbalances at interconnections between BPA's control area and other control areas shall be in accordance with the NERC and WSCC guidelines regarding control area operations.

BPA will establish and maintain separate accounts for HLH and LLH Positive and Negative Deviations for both within and outside the Energy Imbalance Band. The accounts shall be settled at the close of each billing month. For deviations occurring within the Energy Imbalance Band, the rate is applied to the Net Monthly Deviation, which is the difference between the Positive and Negative HLH and LLH deviations for the month.

9. Firm Capacity without Energy

Firm Capacity without Energy is a product available under the PF-96 and NR-96 rate schedules to Computed Requirements customers who hold 1981 Contracts. Customers who buy this product may take power from BPA during HLH and must return the associated energy within 24 hours. This product is also offered under the FPS rate schedule with delivery and return provisions that may differ from those available under the 1981 Contract.

10. Firm Power

Firm Power available at the FPS rate is defined as firm energy with capacity, firm energy without capacity, and/or firm capacity that BPA may make available to the purchaser at BPA's discretion. Energy associated with the delivery of firm capacity must be returned to BPA either before or after delivery of the capacity and in a manner consistent with the agreement between BPA and the Purchaser.

Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP). Firm Power is also available for various unbundled products, including:

a. Power supplied for emergency use;

b. Replacement of lost generation during forced outages;

c. Replacement of lost generation during planned outages;

d. Displacement of higher-cost firm capacity resources which are otherwise available to meet the purchaser's load;

e. Supplemental non-spinning operating reserves; and

f. Other purposes.

11. Firm Transmission Service

Under the Point-to-Point Service Tariff, *Firm Transmission Service* is Long-Term Firm Transmission Service and Short-Term Firm Transmission Service over the FCRTS that is reserved and/or scheduled on a firm basis and that is of the same priority as that of BPA's firm use.

Long-Term Firm Transmission Service is reserved and/or scheduled for a term of one (1) year or more and is of the same priority as that of BPA's firm use of the FCRTS.

Short-Term Firm Transmission Service is reserved and/or scheduled for a minimum duration of one (1) calendar day up to one (1) year and is of the same priority as that of BPA's firm use of the FCRTS.

12. Fixed Curtailment Fee

The *Fixed Curtailment Fee* gives a DSI purchasing take-or-pay energy under a 1996 Contract the right to curtail its plant load below the sum of (1) its take-or-pay obligation and (2) any amount of non-Federal service the customer identifies at the time it elects this curtailment option. The Fixed Curtailment Fee is assessed per kilowatthour of Curtailed Energy.

13. Generation Following

Generation Following is the instantaneous (second-to-second) regulation of the supply of firm power that BPA provides to follow variations in customers' resources *within* the hour.

14. Hourly Nonfirm Transmission Service

Under the Point-to-Point Service Tariff, *Hourly Nonfirm Transmission Service* is Nonfirm Transmission Service over the FCRTS that is scheduled for a Preschedule Period on an hourly basis and that is of the same priority as that of BPA's nonfirm use of the FCRTS.

15. Industrial Exemption

Industrial Exemption is available to customers purchasing Full Load Shaping under the 1981 and 1996 Contracts. Industrial Exemption allows a customer to exempt certain industrial loads from load shaping charges. The exempted industrial load must be separately metered. BPA will not charge for the industrial exemption, but the utility will be required to pay for the actual load shaping BPA provides the exempt load through a separate billing factor and rate. If the exempt load loses its exemption, the industrial load becomes part of the customer's load for calculating the billing factor for Full Load Shaping, and the Utility Factor is used (rather than the Adjusted Utility Factor) to determine the charge for Full Load Shaping. The charge for load shaping for exempted loads is assessed for any (positive or negative) variations from the monthly forecast; the Purchaser also pays the applicable rate for the power delivered. The customer will be charged for (1) the absolute value of the difference between the monthly Industrial Exemption forecast for HLH and the Measured Energy for the Industrial Exemption load for the HLH, plus (2) the absolute value of the difference between the monthly LLH Industrial Exemption forecast and the Measured Energy for the Industrial Exemption load for the LLH.

For each exempted industrial load, the customer must supply BPA with forecasts of monthly HLH and LLH energy at least two months prior to the start of the billing month. The monthly energy forecasts are used to determine the billing factor and to perform a predictability test. The predictability test compares forecasted and actual total monthly energy amounts to determine whether the facility continues to qualify for the Industrial Exemption. If the energy use falls outside of a +1/-5 percent band from the energy forecast for more than 1 month out of any 6-month period, the facility will lose its Industrial Exemption qualification. The monthly power bill outlining a failure of the predictability test will serve as notice that a subsequent failure within the next 5 months will result in losing the exemption. The load will be disqualified for Industrial Exemption, and Full Load Shaping charged, as of the beginning of the second month in which the exempt industrial load fails the predictability test.

16. Industrial Firm Power

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

17. Load Regulation

Load Regulation is the instantaneous (second-to-second) regulation of the supply of firm power that BPA provides to follow variations in customers’ loads *within* the hour. The amount of Load Regulation provided is related to the customer’s retail or plant load. Load Regulation includes service to provide Eccentric Load Following. BPA may offer discounted rates for Load Regulation available under the APS, PF, IP and NR rate schedules pursuant to section II.A of these GRSPs.

18. Load Shaping

Full Load Shaping provides additional or reduced firm power for the monthly difference between a utility purchaser's actual and forecasted retail loads. Load shaping does not cover changes in purchase amounts due to resource operations. *DSI Load Shaping*, available to DSIs under a 1996 Contract only, provides additional firm power or relief from take-or-pay for a variation of up to 15 percent in a DSI customer's actual plant loads above or below forecasted plant operations.

A separate product, *Partial Load Shaping*, is available to Planned Computed Requirements customers under their 1981 Contracts and to Partial Requirements customers under the 1996 Contracts who forecast their Total Retail Load and their BPA purchases. Partial Load Shaping allows the Purchaser to specify an amount of load shaping it will purchase. If the Purchaser's retail load exceeds its forecast, BPA will provide additional demand and energy, limited to the amount specified by the customer. If the Purchaser's retail load is lower than forecast, BPA will relieve the take-or-pay obligation up to the amount of load shaping specified.

19. New Resource Firm Power

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

a. for any New Large Single Load, and

b. for firm power purchased by investor-owned utilities (IOUs) pursuant to power sales contracts with BPA.

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

New Resource Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. New Resource Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP).

20. Nonfirm Energy

Nonfirm Energy is energy that is supplied or made available by BPA to a Purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is sold primarily under the Nonfirm Energy rate schedule, NF-96. Nonfirm energy also may be supplied under the NF-96 rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements. 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.

21. Nonfirm Transmission Service

Under the Point-to-Point Service Tariff (PTP Tariff), *Nonfirm Transmission Service* is Short-Term Nonfirm and Hourly Nonfirm Transmission Service over BPA's FCRTS that is scheduled on an as-available basis and is subject to interruption. Nonfirm Transmission Service is also available in conjunction with reservations of Firm Transmission Service for any term subject to the conditions set forth in Section 14.1 under the PTP Tariff.

22. Non-Spinning Operating Reserve

Non-Spinning Operating Reserve is that portion of the Operating Reserve that does not meet the definition of Spinning Reserve. Generally, non-spinning operating reserve is that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. The Northwest Power Pool requires that each control area maintain a non-spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

23. Operating Reserve

Operating Reserve is the unloaded generating capacity, interruptible load, or other on-demand rights that the customer is able to access within ten (10) minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one (1) hour. Operating reserves includes both spinning reserves and non-spinning operating reserves. The Northwest Power Pool requires that each control area maintain an operating reserve obligation equal to at least 5 percent of all hydro and 7 percent of all thermal and other non-hydro on-line generation within the control area.

24. Power Supplied for Emergency Use

Power Supplied for Emergency Use is electric energy and/or capacity that has been supplied by BPA under the FPS rate schedule:

a. for use during an emergency on the Purchaser's system, or

b. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may be provided under exchange agreements, and payment for that power made in accordance with the terms of those agreements.

25. Priority Firm Power

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

Priority Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. Priority Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP).

26. Reservation and Rights to Change Services

Reservation and Rights to Change Services include the ability to reserve the right to change future deliveries of firm power, firm energy, capacity, unbundled power products, shaping service, and/or features of these deliveries. These services are available under the FPS-96 rate schedule. These services may include:

a. Reservation fees for put or call options;

b. Changes to energy return provisions;

c. Rights to change notice provisions;

d. Preschedule change services; and

e. Other purposes.

27. Reserve Power

Reserve Power is firm power sold to a Purchaser:

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

b. to provide service when no other type of power is deemed applicable; or

c. to serve the Purchaser's firm power loads under circumstances in which BPA does not have a power sales contract in force with the purchaser.

Deliveries of Reserve Power may be reduced or interrupted either as a result of an uncontrollable force or when necessitated by emergencies, system maintenance requirements, or other factors related to continuity of service.

28. Residential Purchase and Sale Agreement (RPSA) Power

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

29. Shaping Services

Shaping Services are services provided by BPA to a Purchaser to shape the output of the Purchaser’s resource (or purchase) to the Purchaser’s load. These services may include accepting and returning energy including load factoring, storage, advance delivery, energy return, and seasonal storage and exchange. Shaping services may be provided on an hourly, daily, weekly, monthly, seasonal, or other basis, and may include advance delivery of the resource (or purchase) to the load. Shaping services are available under the FPS rate schedule on a firm or nonfirm basis and may or may not be packaged with other power products.

30. Short-Term Nonfirm Transmission Service

Under the Point-to-Point Service Tariff, *Short-Term Nonfirm Transmission Service* is Nonfirm Point-to-Point Transmission Service over the FCRTS that is reserved and/or scheduled daily, weekly, or monthly for renewable terms of not more than 30 days each and that is of the same priority as that of BPA's nonfirm use of the FCRTS.

31. 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.

32. Spinning Reserve

Spinning Reserve is the unloaded generating capacity of a system's firm resources that is the portion of Operating Reserve that is synchronized to the power system and provides additional energy as required to be immediately responsive to system frequency. The Northwest Power Pool requires that each control area maintain a spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

33. Supplemental Control Area Services

Supplemental Control Area Services may be used to support control areas of utilities other than BPA and their control area service obligations. These services, which may include load regulation, control area reserves, interconnected operations services, and others, are available under the FPS-96 rate schedule.

34. Transitional Service

Transitional Service is service that BPA provides to a DSI or utility customer that has a large industrial load that is being brought on-line. The load may be a new industrial plant, a major addition to an existing industrial plant, or reactivation of an existing industrial plant or major portion thereof. Pursuant to its agreement with the customer, BPA will serve the load and calculate the customer's monthly Billing Demand to account for the daily variations in the industrial load. To receive this service, the BPA customer must meet the eligibility requirements set forth in BPA's Billing Procedures.

35. Transmission Losses

Transmission Losses are the real power losses associated with the transmission of power over the FCRTS. The loss factor that represents the amount of losses for a specific transaction is included in the wheeling agreement, the rate schedule, or the tariff. The rates for a transmission customer purchasing Transmission Losses appear in the APS-96 rate schedule.

36. Transmission Service

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

37. Variable Industrial Power

Variable Industrial Power is Industrial Firm Power that is sold at the VI-96 rate, consistent with the terms and conditions of the Variable Rate Contract between BPA and the Purchaser.

B. Definition of Rate Schedule Terms

1. 1981 Contract

The *1981 Contract* refers to the initial power sales contracts that BPA executed with its Pacific Northwest customers pursuant to the requirements of sections 5(b) and 5(d) of the Northwest Power Act. Most of these contracts were executed in 1981, but some are dated 1984 or later. For purposes of these rate schedules, any such contract that provides for power deliveries to begin prior to October 1, 1996, is referred to for convenience as a 1981 Contract.

2. 1996 Contract

Contracts for the sale of firm power to Pacific Northwest customers pursuant to the requirements of sections 5(b) and 5(d) of the Northwest Power Act are termed the *1996 Contracts* if they provide for power deliveries to begin on or after October 1, 1996.

3. Actual Customer-Served Load

Actual Customer-Served Load is the actual hourly amount of the Network Load in megawatts that the customer serves on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement or 1996 Contract.

4. Adjusted Measured Energy

Adjusted Measured Energy is the Measured Energy for the month under the applicable PF, NR, IP, or IPG rate *less* any Unauthorized Positive Deviations *plus* any Unauthorized Negative Deviations for the hour, day, or month.

5. Adjusted Utility Factor

The *Adjusted Utility Factor* modifies the Full Load Shaping rate for utility customers purchasing under a 1981 Contract that have an Industrial Exemption. The Adjusted Utility Factor is calculated and applied monthly based on the Purchaser’s average historical load and its forecast exempt industrial load for the month. For Metered Requirements customers, the calculation also is based on their BPA purchases for the last year. For Computed Requirements customers, the calculation also is based on their Computed Energy Maximum for the last year. See section II, Utility Factor.

6. Annual Billing Cycle

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

7. Authorized Deviation

Authorized Deviation is the limited amount of Deviation from Contract Obligation that a Purchaser is allowed under its 1996 Contract without incurring an Unauthorized Increase Charge or an adjustment for take-or-pay obligation. *Authorized Positive Deviation* is the limited amount the Purchaser's Measured Energy may exceed the Purchaser's Contract Obligation on an hour, day, or month without incurring an Unauthorized Increase Charge. *Authorized Negative Deviation* is the limited amount the Purchaser's Measured Energy may be less than the Purchaser's Contract Obligation on an hour, day, or month without an adjustment to the Measured Energy for take-or-pay obligation.

8. Auxiliary Demand *{1981 DSI Contract}*

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. Auxiliary Power is power in excess of the DSI's Operating Demand. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's 1981 Contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power rate schedule.

9. Billing Demand (Energy)

The Purchaser's *Billing Demand (Energy)* is the amount of capacity (energy) to which the demand (energy) charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand (Energy) quantity for each product. BPA establishes Billing Demand and Billing Energy quantities for both active power (kilowatts and kilowatthours) and reactive power (kilovars and kilovarhours). Billing Demand (Energy) may be adjusted for certain outages (providing the Purchaser an Outage Credit or authorized negative deviation) as specified in the Purchaser's agreement with BPA and pursuant to BPA's Billing Procedures.

At any POD that has an unbalanced phase current problem, BPA shall calculate the Billing Demand by multiplying the largest of the adjusted Integrated Demands on any phase at the time of the applicable monthly system peak hour by three. BPA may continue this billing procedure until the Purchaser has made the necessary system corrections.

10. BPA Operating Level *{1981 DSI Contract}*

The *BPA Operating Level* is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand; or

c. Restricted Demand.

Each DSI must request service from BPA for each billing month in accordance with the terms of its power sales contract. The requested level of service under the 1981 Contract will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request, and BPA may agree to provide, a level of service for the Offpeak Period that differs from that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an Unauthorized Increase.

Any DSI whose Measured Demand during any single hour exceeds the BPA Operating Level for that hour shall be subject to an Unauthorized Increase Charge for each kilowatt and kilowatthour of unauthorized increase associated with each such overrun.

11. Calculated Energy Capacity

Calculated Energy Capacity is the billing factor for DSI Load Shaping. BPA's estimate of Calculated Energy Capacity is based on the amount of energy load (aMW) that a DSI would consume at a particular separately metered facility when that facility is operating at full capacity.

12. Composite Rate

The *Composite Rate* applies to PF-96 Purchasers under 1981 and 1996 Contracts. Only customers whose average annual energy loads during the 5-year period, as forecasted by BPA, are 25 average annual MW or less are eligible to purchase at this rate. The composite rate is a weighted average rate that takes into account the relative cost of typical quantities of each product purchased, including generation demand and energy, load shaping, and load regulation.

13. Computed Average Energy Requirement *{1981 Utility Contract}*

For Computed Requirements customers, the *Computed Average Energy Requirement* shall be determined as specified in the Purchaser's 1981 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 customers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for Planned Computed Requirements customers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for Contracted Computed Requirements customers.

For Planned Computed Requirements customers purchasing Partial Load Shaping, the Computed Average Energy Requirement shall be adjusted by the lesser of (1) the absolute value of the Purchaser's actual Total Retail Load *minus* the Purchaser's forecasted Total Retail Load, or (2) the Partial Load Shaping Purchase Amount. For variations above forecast, the adjustment shall be added to CAER; for deviations below forecast, the adjustment shall be subtracted from CAER.

14. Computed Energy Maximum *{1981 Utility Contract}*

The *Computed Energy Maximum* equals the Computed Average Energy Requirement (CAER) multiplied by the number of hours in the billing month.

15. Computed Maximum Requirement *{1981 Utility Contract}*

The Purchaser's *Computed Maximum Requirement* is the maximum amount of power that BPA is obligated to deliver to the Purchaser during the HLH of a month. The Computed Maximum Requirement is defined in section 17(g)(1) of the Purchaser's 1981 Contract as the greater of the Purchaser's Computed Peak Requirement and its Computed Average Energy Requirement unless the terms of section 7 ("Allocation Provisions in the Event of Planning Insufficiency") apply. The Purchaser may waive its right to schedule a portion of its Computed

Maximum Requirement, as specified in an agreement between BPA and the Purchaser.

16. Computed Peak Requirement *{1981 Utility Contract}*

For Computed Requirements customers, the *Computed Peak Requirement* shall be determined as specified in the Purchaser's 1981 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 customers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for Planned Computed Requirements customers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for Contracted Computed Requirements customers.

For Planned Computed Requirements customers purchasing Partial Load Shaping, the Computed Peak Requirement shall be adjusted by the lesser of (1) the absolute value of the Purchaser’s actual Total Retail Load *minus* the Purchaser’s forecasted Total Retail Load, or (2) the Partial Load Shaping Purchase Amount. For variations above forecast, the adjustment shall be added to CPR; for deviations below forecast, the adjustment shall be subtracted from CPR.

17. Computed Requirements Customer *{1981 Utility Contract}*

A *Computed Requirements Customer* is a Purchaser of Priority Firm and/or New Resource Firm Power who is designated as a Computed Requirements Customer by the terms of its 1981 contract.

18. Contract Demand

The *Contract Demand* shall be the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the Purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term "Contract Energy."

19. Contract Energy

Contract Energy is the maximum number of kilowatthours that BPA agrees to make available subject to any limitations included in the applicable contract between BPA and the Purchaser. Contract Energy may refer to an energy purchase from BPA or to an amount of energy that BPA agrees to transmit over the FCRTS. For the purpose of these GRSPs, Contract Energy is deemed to refer to any contractual or other reference to Contract Demand as expressed in kilowatthours.

20. Contract Obligation

A customer's *Contract Obligation* is a function of a customer's purchase of products under its 1996 Contract. A customer's Contract Obligation for a month, day, or hour is determined from its purchase commitment or resource commitment, its Total Retail Load or Total Plant Load if purchasing any Load Shaping products, and any minimum or maximum scheduling limits for any hour. The actual description of the Purchaser's Contract Obligation is provided in the Purchaser's 1996 Contract.

21. Control Area

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

22. Curtailed Demand *{1981 DSI Contract}*

A *Curtailed Demand* is the number of kilowatts of Industrial Firm Power during the billing month that results from a DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of Industrial Firm Power may curtail its demand according to the terms of its 1981 Contract (which permits up to three levels of Curtailed Demand each month).

23. Curtailed Energy

Curtailed Energy is the billing factor for the Fixed Curtailment Fee and is equal to the reduction(s) in the DSI customer's purchase of energy from BPA due to the Purchaser exercising its contractual right to curtail.

24. Declared Customer-Served Load

Declared Customer-Served Load (Declared CSL) is the Network Load in megawatts that the customer elects to serve on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement or 1996 Contract. The customer's Declared CSL is contractually specified for each month.

25. Decremental Cost

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

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

b. All identifiable costs (expressed in mills per kilowatthour) 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.

26. Delivering Party

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

27. Deviation *{1996 Contract}*

Deviation is the difference between the quantity of power that was actually taken from BPA (Measured Energy) and the quantity of power the customer is entitled to receive under its Contract Obligation.

28. Direct Assignment Facilities

Direct Assignment Facilities are facilities that have been or are constructed (or caused to be constructed) by BPA for the sole use and benefit of facilitating a request for service. The costs of such facilities may be directly assigned to the Transmission Customer requesting the service in accordance with applicable FERC policy. The cost of Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer.

29. Direct Service Industry (DSI) Delivery

The *DSI Delivery* segment is that segment of the FCRTS that provides service to DSI customers at voltages of 34.5 kV and below.

30. Diverted Power

Diverted Power is PF, NR, or IP Firm Power delivered at the customer's request and for the purpose of storage or exchange, but not resale, to points of delivery other than the Points of Delivery serving the customer's Total Retail Load or Total Plant Load.

31. Eastern Intertie

The *Eastern Intertie* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

32. Electric Power

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

33. Federal Columbia River Transmission System

The *Federal Columbia River Transmission System* (FCRTS) is 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.

34. Federal System

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

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

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

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

35. Full Requirements Customer *{1996 Contract}*

A *Full Requirements Customer* is a customer that has been designated by BPA as a Full Requirements Customer under the terms of its 1996 Contract. Full Requirements Customers are those purchasers under 1996 Contracts: (a) with no resource; or (b) that have contracted for services with BPA for their resource(s) so that the purchaser retains Full Requirements status.

36. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the Peak Period (6 a.m. to 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable)). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

37. Integrated Demand

Integrated Demand is the quantity derived by mathematically "integrating" kilowatthour deliveries over a 60-minute period.

38. Intentional Deviation

Intentional Deviation, for the purpose of determining credit or payment for Negative Deviations under the Energy Imbalance rate, is defined as the intentional creation by the purchaser of a difference between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with transmission to a load located in BPA's control area or from a generation resource located within BPA's control area. A deviation will be deemed intentional by BPA if the following patterns occur: 1) chronic Negative Deviations received during multiple hours in a row or at specific times during the day; 2) chronic Positive Deviations received during either winter storm or HLH with corresponding Negative Deviations in LLH; 3) chronic Negative Deviations during LLH or otherwise lightly loaded system conditions; particularly when the purchaser does not respond by adjusting schedules for future days to attempt to correct for these tendencies.

39. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the Offpeak Period (10 p.m. to 6 a.m. Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable)).

40. Main Grid

As used in the FPT rate schedule, the *Main Grid* is that portion of the Network facilities with an operating voltage of 230 kV or more.

41. Main Grid Distance

As used in the FPT rate schedules, *Main Grid Distance* is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

42. Main Grid Interconnection Terminal

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

43. Main Grid Miscellaneous Facilities

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

44. Main Grid Terminal

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

45. Measured Demand

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

In determining Measured Demand for any Purchaser who experiences an outage as defined in the Purchaser’s agreement with BPA and in BPA’s Billing Procedures, BPA shall exclude any abnormal Integrated Demand due to, or resulting from:

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

b. emergencies on the Purchaser's facilities to the extent Bonneville determines that such facilities have been adequately maintained and prudently operated.

Partial interruptions shall be converted to an equivalent outage of total Measured Demand.

46. Measured Energy

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

47. Metered Demand

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

a. at each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand,

b. during each time period specified in the applicable rate schedule, and

c. during any billing period.

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

48. Metered Energy

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

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

b. during any billing period.

49. Metered Requirements Customer

A *Metered Requirements Customer* is a customer that has been designated as such under the terms of its 1981 Contract.

50. Minimum HLH (LLH) Contract Obligation

The Minimum HLH (LLH) Contract Obligation is 99 percent of the customer's Monthly Contract Obligation for HLH (LLH) energy minus any adjustments specified in the contract for the occurrence of specific operational events.

51. Montana Intertie

The *Montana Intertie* is the regional double-circuit 500 kV transmission intertie from Broadview Substation to Garrison Substation.

52. Monthly Federal System Peak Load

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

53. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the peak loading on the Federal transmission system during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's control area and metered flow into BPA's control area.

54. Negative Deviation

Negative Deviation under the 1996 Contract is the difference between the Purchaser's Contract Obligation and Measured Energy on the hour, day, or month, where the Purchaser's Measured Energy is less than its Contract Obligation. *Negative Deviation* under the Energy Imbalance service occurs on any hour when BPA receives more energy from the Delivering Party at the Point of Integration than BPA delivers to the Receiving Party at the Point of Delivery.

55. Network (or Integrated Network)

The *Network* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest.

56. Network Load

Network Load is the Load of a Transmission Customer, including the entire load of all Member Systems designated pursuant to Section 6 of the Network Integration (NT) Service Tariff. Network Load includes the retail energy load during any given time period plus distribution losses and system power requirements. A Transmission Customer's Network Load shall not be reduced to reflect any portion of such load served by the output of any generating facilities owned, or generation purchased, by the Transmission Customer, its Member Systems, or other customers it serves under the NT Tariff.

57. Network Upgrades

Network Upgrades are modifications and/or additions to transmission-related facilities that are integrated with and support BPA's transmission system to satisfy, at least in part, an Application for transmission service as well as provide for the general benefit of users of such transmission system.

58. Northern Intertie

Northern Intertie describes a subset of Network facilities that interconnect the FCRTS to Canada. Northern Intertie facilities were formerly identified as a separate FCRTS segment, but are now subsumed in the Network segment.

59. Offpeak Period

The *Offpeak Period* (or LLH) includes all hours that do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 6 a.m., Monday through Saturday, and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

60. Operating Demand *{1981 DSI Contract}*

The *Operating Demand* is that demand which is established by each DSI in accordance with section 5(b) of the DSI's 1981 Contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the hourly demand that the purchaser may impose on BPA; and

b. the total amount of energy during a billing month that the DSI is entitled to purchase from BPA.

61. Opportunity Cost

Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. Opportunity Cost shall be determined consistent with FERC policy.

62. Partial Load Shaping Purchase Amount

Partial Load Shaping Purchase Amount means the absolute value in megawatthours per hour of positive or negative variations from forecast purchased by the Purchaser. The *Partial Load Shaping Purchase Amount for the month,* the billing factor for Partial Load Shaping, is the Partial Load Shaping Purchase Amount times the hours in the month.

63. Partial Requirements Customer *{1996 Contract}*

A *Partial Requirements Customer* is a Purchaser (utility, Federal agency, or DSI) that is designated as a Partial Requirements Customer by the terms of its 1996 Contract. A Purchaser under any 1996 Contract that does not specifically identify a customer as Full Requirements or Partial Requirements shall be considered to be a Partial Requirements Customer. Partial Requirements Customers are those purchasers under 1996 Contracts that are responsible for managing the operation of generation resources or purchases to serve their Total Retail Load or Total Plant Load in specific amounts.

64. Peak Period

The *Peak Period* (or HLH) includes the hours from 6 a.m. to 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

65. Phase-In Mitigation

Phase-In Mitigation is available to Full and Metered Requirements Preference Purchasers who are purchasing their firm requirements under one or more of BPA's 5-year rate schedules and whose FY 1997 rate increase for BPA purchases is at least 9 percent. If the purchaser meets the eligibility criteria and requests that BPA phase in its rate increase, BPA will limit the Purchaser's annual rate increase to 9 percent each year for the 5-year period.

66. Point of Delivery (POD)

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

67. Point of Integration (POI)

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

68. Point of Interconnection (POI)

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

69. Positive Deviation

Positive Deviation under the 1996 Contract is the difference between the Purchaser's Measured Energy and Contract Obligation on the hour, day, or month, where the Purchaser's Measured Energy exceeds its Contract Obligation. *Positive Deviation* under the Energy Imbalance service occurs on any hour when BPA delivers more energy to the Receiving Party at the Point of Delivery than BPA receives from the Delivering Party at the Point of Integration.

70. **Purchaser**

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

71. **Ratchet Demand**

The *Ratchet Demand* in kilowatts or kilovars is the maximum demand established during a specified period of time either during, or prior to, the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. When the Ratchet Demand is used as a billing factor, BPA shall have specified the following information in the appropriate rate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated;

b. the type of demand to be used in the calculation; and

c. the percentage (if any) of that demand that will be used to calculate the Ratchet Demand.

72. **Reactive Power**

Reactive Power is the out-of-phase component of the total voltamperes in an electric circuit. Reactive Power has two components: reactive demand (expressed in kilovars or kVAr) and reactive energy (expressed in kilovarhours or kVArh).

73. **Receiving Party**

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

74. **Restricted Demand** ***{1981 DSI Contract}***

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

75. Scheduled Demand

The *Scheduled Demand* in kilowatts is the largest of the hourly demands at which electric energy is scheduled for transmission on the FCRTS for delivery to a purchaser:

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

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

c. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining Billing Demand.

76. Scheduled Energy

The *Scheduled Energy* in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

a. for each system for which scheduled energy is the basis for determination of the Measured Energy, and

b. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining Billing Energy.

77. Secondary System

As used in the FPT rate schedules, *Secondary System* is that portion of the Network facilities with an operating voltage between 69 kV to less than 230 kV.

78. Secondary System Distance

As used in the FPT rate schedules, *Secondary System Distance* is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

79. Secondary System Interconnection Terminal

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

80. Secondary System Intermediate Terminal

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

81. Secondary Transformation

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

82. Southern Intertie

The *Southern Intertie* is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; and the 500 kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

83. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Negative Deviations under the Energy Imbalance rate, exists when any one or more of the following conditions exist or events occur on the BPA system: high flows and full reservoirs; flood control implementation; spill priority implementation procedures; spill due to lack of Federal load; spill past unloaded turbines; minimum generation requirements; increased spill due to storage; BPA is not accepting Coordination storage due to lack of storage or a specified flow requirement. Discretionary spill, where BPA may choose whether to spill does not constitute a Spill Condition.

84. Total Plant Load

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

85. Total Retail Load

For utilities, *Total Retail Load* is the customer's regional retail energy load during any given time period plus distribution losses and the customer's system power requirements. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, Total Retail Load is called Total Plant Load.

86. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable Agreement.

87. Transmission Customer

A *Transmission Customer* is an Eligible Customer that executes an Network Integration (NT) or Point-to-Point (PTP) Service Agreement or receives service under the NT Tariff or PTP Tariff.

88. Transmission Demand

Transmission Demand is the maximum amount of capacity and/or energy that BPA agrees to transit for the transmission customer over BPA's Federal Columbia River Transmission System between the Point(s) of Interconnection/Integration and the Point(s) of Delivery. Transmission Demand shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

89. Unauthorized Deviation

Unauthorized Deviation under the 1996 Contract is the amount of Deviation in excess of the Authorized Deviation on any hour, day, or month, and the amount of Rate Period Excess Purchase and Unreturned Diverted Power during an Annual Billing Cycle. *Unauthorized Positive Deviations* are amounts of Measured Energy in excess of the Contract Obligation that exceed the limits allowed for Authorized Deviation on any hour, day, or month, and the amount of Rate Period Excess Purchases and Unreturned Diverted Power. Unauthorized Positive Deviations are subtracted from Measured Energy and billed at the Unauthorized Increase Charge. *Unauthorized Negative Deviations* are amounts of Measured Energy less than the Contract Obligation that exceed the limits allowed for Authorized Deviation on any hour, day, or month. Unauthorized Negative Deviations are treated as take-or-pay amounts, added to the Measured Energy, and billed at the appropriate PF, NR, or IP rate.

90. Utility Delivery

The *Utility Delivery* segment is that segment of the FCRTS that provides service to utility customers at voltages below 34.5 kV.

91. Utility Factor

The *Utility Factor* modifies the charges for Full Load Shaping and Load Regulation for customers purchasing under a 1981 Contract. The Utility Factor is calculated and applied annually based on historical data for the Purchaser's Total Retail Load. For Metered Requirements customers, the calculation also is based on their energy purchases from BPA. For Computed Requirements customers, the calculation also is based on their Computed Energy Maximum.