BONNEVILLE POWER ADMINISTRATION

TRANSMISSION BUSINESS LINE

2002 INITIAL PROPOSAL

TRANSMISSION RATE STUDY

March 2000

TR-02-E-BPA-03

TRANSMISSION RATE STUDY
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COMMONLY USED ACRONYMS

AC	Alternating Current
ACS	Ancillary Services and Control Area Services (Rate)
AF	Advance Funding (Rate)
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
ASC	Average System Cost
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
Btu	British Thermal Unit
CA	Control Area
CAISO	California Independent System Operator
California PX	California Power Exchange
CAS	Control Area Service
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
CPTC	Columbia Power Trades Council
CRAC	Cost Recovery Adjustment Clause
CSL	Customer-Served Load
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DOE	Department of Energy
DOI	Department of Interior
DSIs	Direct Service Industrial Customers
EIA	Energy Information Administration
Energy Northwest	Formerly Washington Public Power Supply System Project
F&O	Financial and Operating Reports
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FPT	Formula Power Transmission Rate
FTE	Full-time Equivalent
FY	Fiscal Year (Oct-Sep)
GDP	Gross Domestic Product
GI	Generation Integration
GRSPs	General Rate Schedule Provisions
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hours
HNF	Hourly Non-Firm

IDC	Interest During Construction
IE	Eastern Intertie (Rate)
IM	Montana Intertie (Rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (Rate)
IR	Integration of Resources (Rate)
IS	Southern Intertie (Rate)
ISC	Investment Service Coverage
ISO	Independent System Operator
kcfs	kilo (thousands) of cubic feet per second
kV	Kilovolt (1000 volts)
kVAr	Kilovoltampere Reactive
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LLH	Light Load Hours
m/kWh	Mills per kilowatthour
MAF	Million Acre Feet
MORC	Minimum Operating Reliability Criteria
MTPL	Monthly Transmission Peak Load
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Network Contract Demand (Service and Rate)
NERC	North American Electric Reliability Council
NF	Nonfirm Energy
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NT	Network Integration Transmission (Service and Rate)
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMB	Office of Management and Budget
OY	Operating Year (Aug-Jul)
PA	Public Agency
PBL	Power Business Line
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration (or, Interconnection)

POR	Point of Receipt
PSW	Pacific Southwest
PTP	Point to Point (Service and Rate)
PUD	Public or People's Utility District
Reclamation	Bureau of Reclamation
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase Sale Agreement
RRS	Revenue Requirement Study
RTO	Regional Transmission Organization
SCADA	Supervisory Control And Data Acquisition System
Tariff	Open Access Transmission Tariff
TBL	Transmission Business Line
TCH	Transmission Contract Holder
TGT	Townsend-Garrison Transmission (Rate)
TPP	Treasury Payment Probability
TRAP	Transmission Risk Analysis Processor
TRS	Transmission Rate Study
TTSL	Total Transmission System Loading
UIC	Unauthorized Increase Charge
UFT	Use of Facilities (Rate)
USBOR	U.S. Bureau of Reclamation
VOR	Value of Reserves
WEFA	Wharton Econometric Forecasting Associates
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
1CP	One Coincidental Peak
12CP	Twelve Coincidental Peak

1. INTRODUCTION

1.1 Purpose

The Transmission Rate Study (TRS) presents an overview of the Bonneville Power Administration (BPA) Transmission Business Line (TBL) rate design process for developing the proposed transmission and ancillary service rates. The end result of the TRS is the transmission and ancillary service rate schedules and associated General Rate Schedule Provisions (GRSP) that are published in the Transmission and Ancillary Service Rate Schedules and General Rate Schedule Provisions (TR-02-E-BPA-04). A summary of the proposed rates is shown in Table 13.

TBL proposes to set transmission rates for a two year rate period -- Fiscal Years (FYs) 2002 and 2003. (A fiscal year runs from October 1 through September 30.) A two-year rate period recognizes that the region is working toward establishing a Regional Transmission Organization pursuant to Federal Energy Regulatory Commission Order 2000. Beginning October 1, 2001, all customers will purchase new transmission service under the Open Access Transmission Tariff (Tariff). TBL is revising the Tariff to include three services: Network Integration (NT), Point-to-Point (PTP), and the new Network Contract Demand (NCD) service.

The overall level and design of transmission rates is governed by BPA's statutory obligations, commitment to comparability, contractual arrangements, the resolution of interbusiness line issues, and the consideration of other factors such as revenue stability, rate continuity, and ease of administration. The TRS first briefly discusses some of these factors and then discusses the methodology used to develop the rates.

1.2 Overview of the Basis for Rate Development

Factors influencing the level and design of transmission rates are statutory obligations, comparability, interbusiness line issues to be resolved in the 2002 Power Rate Case, and contractual arrangements.

1.2.1 Statutes

In accordance with section 4 of the Federal Columbia River Transmission System Act (Transmission System Act), BPA constructs, operates, and maintains the Federal Columbia River Transmission System (FCRTS) to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide interregional transmission facilities; and (d) maintain the electrical stability and reliability of the Federal system. 16 U.S.C. §838b.

BPA's transmission rates are established in accordance with sections 9 and 10 of the Transmission System Act (16 U.S.C. §§838g and h), section 5 of the Flood Control Act of 1944 (16 U.S.C. §825s), and the provisions of section 7 of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act). 16 U.S.C. §839e. Section 7(a)(2)(C) of the Northwest Power Act requires that BPA ". . . equitably allocate the costs of the Federal transmission system between

Federal and non-Federal power utilizing such system." 16 U.S.C. §839e(a)(2)(C). Some of BPA's transmission rates are also prepared in accordance with section 212(i)(1)(b)(ii) of the Federal Power Act, as amended by the Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776. 16 U.S.C. §824k(i)(1)(B)(ii).

1.2.2 <u>Comparability</u>

In the Energy Policy Act of 1992 (EPA'92), Congress approved amendments to sections 211 and 212 of the Federal Power Act that allow the Federal Energy Regulatory Commission (FERC) to order access to utility transmission systems, including the FCRTS. 16 U.S.C. §§824j and 824k(i)(1). Since passage of EPA'92, FERC has developed standards for providing comparable access to transmission services. *American Electric Power Service Corp.*, 64 F.E.R.C. ¶61,279 (1993), *reh'g granted*, 67 F.E.R.C. ¶61,168, *clarified*, 67 F.E.R.C. ¶61,317 (1994). "Comparable" refers to FERC's standard for determining whether access to transmission services is unduly discriminatory or anticompetitive. The analysis focuses on a determination of whether the transmitting utility is offering third parties access to its transmission facilities with the same or comparable terms and conditions, and at the same or comparable rates, that the utility uses for itself. *Id.* at 61,490.

FERC also issued a transmission pricing policy as a further action to address a more competitive electric industry. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 59 Fed. Reg. ¶55,301, FERC Stats. & Regs. ¶31,005 (1994)

(Transmission Pricing Policy). See also 69 F.E.R.C. ¶61,086 (1994). The Transmission Pricing Policy is based on the premise that access to transmission services at comparable prices is critical to the development of competitive wholesale power markets.

On April 24, 1996, FERC issued its final rule *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21,540, FERC Stats. & Regs. ¶31,036 (1996) (Order 888). In Order 888, FERC requires all transmission-owning public utilities subject to FERC jurisdiction to file non-discriminatory open access transmission tariffs. Order 888 also requires jurisdictional utilities to take transmission service, including ancillary services, for their own new wholesale electric sales and purchases under the open access tariffs. *Id.* at 21,552. While Order 888, by its terms, does not apply directly to BPA, FERC declared its intention to apply the policies announced therein as broadly as possible through sections 211 and 212 of the Federal Power Act, to promote a national policy of open transmission access. *Id.* at 21,573. BPA has determined it will comply with Order 888 to the extent it is compatible with existing legislative authority.

In a process concurrent with the 2002 transmission rate case, TBL has proposed terms and conditions of general applicability for open access transmission service, including Network Integration service, Point-to-Point service, and the new Network Contract Demand service. TBL's tariff is modeled on the FERC *pro forma* tariff. In conjunction with the proposed open access transmission services, TBL proposes the Network Integration (NT) rate, Point-to-Point (PTP) rate, Network Contract Demand (NCD) rate, Southern Intertie (IS) rate, and Montana Intertie (IM) rate. TBL also proposes the Ancillary Services and Control Area Services (ACS) rate. In addition, the Integration of Resources (IR) rate and the Formula Power Transmission (FPT) rates are proposed for pre-Tariff firm wheeling contracts.

1.2.3 <u>Interbusiness Line Issues</u>

Certain issues that affect the transmission and ancillary service rates are being decided in the 2002 Power Rate Case. These issues are: a methodology for functionalizing costs between generation and transmission, including a methodology for functionalizing corporate overhead costs to the business lines; unit costs for generation inputs for operating reserves and regulation ancillary services; the generation input cost for reactive supply and voltage control from generation sources; the generation costs of station service and remedial action schemes; and the allocation of generation integration and generator step-up transformer costs to the business lines. Also being decided in the Power Rate Case is a treatment for costs over third-party transmission systems (General Transfer Agreements or their replacement) for the delivery of Federal and non-Federal power, and the Power Business Line's (PBL's) financial support of the Delivery Charge. In calculating the proposed transmission and ancillary services rates, TBL has relied upon the applicable sections of the 2002 Power Rate Case Initial Proposal. The final transmission rate proposal will reflect the Administrator's decisions in the final power rates Record of Decision.

1.2.4 Contractual Arrangements

TBL and its customers enter into transmission agreements that can affect the transmission rates charged customers. Transmission agreements negotiated prior to the Transmission System Act reflect conditions and policies prevalent at the time of negotiation. For example, some agreements to which the Formula Power Transmission (FPT) rate applies specify that transmission rates can be changed annually, while other agreements limit rate adjustments to once every 3 years. TBL will honor these agreements when setting and applying the new transmission rates.

2. TRANSMISSION RATE METHODOLOGY

2.1 Rate Construct

TBL proposes to set the PTP rate, the IR rate, and the NT Base Charge equal to each other, and to set the new NCD rate at the same level. This rate generally will be referred to as the "Base Charge." The FPT rate is not included in this construct because of its different rate design. Network cost, net of FPT revenues, is used to calculate the Base Charge using a one coincidental peak (1CP) method. The Network cost remaining after setting the Base Charge is the basis for the NT Load Shaping Charge.

In the calculation of Network and Intertie rates, TBL forecasts transmission sales under each service. The Power Business Line (PBL) uses the transmission system under Open Access service agreements. PBL use is forecasted in the same manner as for all other transmission customers. Firm PTP contract demands are assigned to PBL's grandfathered sales and exchanges, consistent with current treatment of these bundled contracts.

2.2 Cost

BPA determines a transmission revenue requirement that is divided among identified segments of the FCRTS. The Segmentation Study (TR-02-E-BPA-02) identifies the transmission facilities and associated investment and O&M cost for each transmission segment and, thus, provides a basis for segmenting the revenue requirement. The Revenue Requirement Study (TR-02-E-BPA-01) determines the test period revenue requirement for transmission and ancillary services. From that, the revenue requirement for each segment is determined.

2.2.1 Segmentation Study

TBL operates and maintains the FCRTS to provide transmission services throughout the Pacific Northwest (PNW) region. Because many services do not require the use of the entire system, the Segmentation Study categorizes the facilities of the FCRTS according to the types of services they provide. The Segmentation Study produces the segmented historical FCRTS investment base and the segmented averages of the last 3 years' actual operations and maintenance (O&M) expenses for the transmission segments. The Study also provides the historical investment base and test year O&M associated with ancillary services. This provides the basis for segmenting the revenue requirements used to develop rates. Corps of Engineers (COE) and Bureau of Reclamation (USBR) transmission facilities are not included in the Segmentation Study. Instead, COE and USBR Network and Delivery transmission costs are included in the PBL revenue requirements and charged to the TBL through interbusiness line transfers.

In the Segmentation Study, the FCRTS is divided into six transmission segments: (1) Network (or, Integrated Network); (2) Southern Intertie; (3) Eastern Intertie; (4) Generation Integration; (5) Utility Delivery; and (6) Direct Service Industry (DSI) Delivery. The Utility Delivery and DSI Delivery segments include facilities with voltages below 34.5 kV.

2.2.2 Revenue Requirement Study

In compliance with the FERC order dated January 27, 1984 (26 F.E.R.C. ¶61,096 (1984)), BPA determines separate revenue requirements for the generation and transmission functions of the FCRPS. The Revenue Requirement Study for transmission is prepared consistent with BPA's statutory obligation to set rates to recover, in accordance with sound business principles, all costs of transmitting electric power, including the repayment of the Federal investment in the FCRTS over a reasonable number of years, and all other FCRTS costs.

The process used to develop each revenue requirement consists of three parts. First, repayment studies are prepared for the transmission function to determine the projected annual interest expense and amortization of the Federal investment. These studies are conducted for the rate test period and extend through the repayment period. Second, projections of annual operating expenses of the FCRPS are compiled. Third, planned net revenues determined by the Administrator's financial objectives are calculated and added to the operating and net interest expense.

Thus, transmission revenue requirements are set at levels sufficient to meet the annual operating expenses of the FCRTS, to cover interest expense, and to recover planned net revenues that ensure BPA's ability to make annual amortization payments on the Federal investment as determined by the transmission repayment studies. The segmented transmission revenue requirements for FYs 2002 and 2003 are shown in Table 1.

2.2.2.1 General Transfer Agreement (GTA) Cost

The revenue requirement includes a cost item for "General Transfer Agreements for nonfederal power." *See* Table 1, lines 1.11 and 1.28. In the 2002 Power Rate Case Initial Proposal, the TBL proposed to pay up to $6.5 million annually to acquire Network-equivalent transmission for the non-Federal power purchases of GTA customers and to roll this cost into the Network. TBL forecasts this cost to be $4.365 million per year. *See* Appendix H for the GTA cost forecast.

2.2.3 Revenue Credits and Cost Adjustments

The segmented transmission revenue requirement is adjusted for revenue credits to arrive at the segment costs used to set the adjustable transmission rates (referred to in the TRS tables as "rate development costs"). Expected revenues from various sources are identified and segmented in Table 2. These revenue credits are transmission revenues from sources other than the general transmission rates developed in the TRS.

The segmented revenue credits are subtracted from the appropriate segment revenue requirement before costs are allocated. *See* Table 3. Two additional adjustments are made to the revenue requirement to determine the "rate development costs" used to calculate the adjustable rates. The net cost of the Eastern Intertie is allocated and the stability reserves credit is calculated and allocated. The net cost of the Eastern Intertie equals the Eastern Intertie revenue requirement less the expected revenues from the Townsend-Garrison Transmission rate. The net cost is allocated to the remaining segments based on net plant in each segment.

Table 3 also shows the calculation of the stability reserves credit of $0.496 million per year. The DSI IR and PTP contracts provide for a credit to be given to DSIs for TBL's right to instantaneously disconnect DSI loads from the electrical power system using a high-speed load-tripping scheme known as the Import Contingency Load Tripping Scheme. This system protects against Southern Intertie outages when the Intertie is used to import power into the PNW. The credit is a formula rate based on the change in the Industrial Firm Power (IP) rate. The stability reserves reservation fee currently in effect is applied to forecasted DSI transmission demand for smelter loads. The rate will be updated for the final transmission rate proposal based on the final proposed 2002 IP rate. The cost of providing the stability reserves credit is segmented to the Southern Intertie.

Finally, the Generation Integration segment is comprised of transmission facilities that integrate Federal resources to the Network. The cost of the Generation Integration segment, $7.676 million per year (Table 3, column A, line 3.15), is assigned wholly to the PBL and recovered through power rate charges, as proposed in the 2002 Power Rate Case Initial Proposal.

2.3 <u>Loads</u>

Transmission loads on the Network and Southern Intertie are forecast using contract demands in long-term contracts, point of delivery load forecasts for NT service, and FY 1998 and 1999 short-term sales. The load forecasts are shown on Tables 4 and 5. For the forecast of Network and Southern Intertie loads, TBL first determined current contract demands that are effective through the FY 2002 and 2003 rate period. Then, for the Network, TBL forecasted which Network service(s) it expects will be used by the remaining customers. For rate development purposes, it is important to forecast whether the customer will purchase a contract demand service where the billing factor is a contractually specified demand, or the NT load-based service where the billing factor is based on customer's load.

Customers have a number of choices with regard to Network transmission service and have options to switch their current service to a Tariff service. With the addition of NCD service, TBL will have five long-term firm services on the Network. The proposed Tariff provides a window to allow customers to convert their current service to any Tariff service (PTP, NCD, NT). In addition to the conversion option, customers who are currently taking transmission service under their 1981 power sales contracts, or whose existing PTP, IR, FPT, or NT agreements are expiring before October 1, 2001, must select a Network service.

2.3.1 <u>Sales from Long-Term Contracts</u>

Long-term Network and Southern Intertie transmission demands are shown in Table 4. The demands for FPT, IR and PTP on the Network and Southern Intertie reflect current contracts that are effective during the forecast period. Two PTP contracts that expire in FY 2001 were assumed to extend through the rate period. PTP service on the Network and Southern Intertie is shown separately for PBL grandfathered contracts and for all other PTP service agreements.

For the customers that are not covered by a current long-term contract, loads and revenues are forecasted for both NT and NCD service in order to determine which service the customer would likely take. *See* section 2.3.1.1, Network Rate Choice. Non-generating public utility load forecasts are based on an analysis of recent history. Appendix D describes the non-generating public utility load forecast methodology and provides a list of the utilities that this method was used for. The forecasted non-generating utility monthly loads coincident with TBL's monthly system peak are the NT Load Shaping Charge billing determinants. These same monthly loads, adjusted for Customer Served Load (CSL), are the NT Base Charge billing determinants. Load served under IR, FPT, and PTP contracts is considered to be CSL. NCD demands are forecast to be each utility's highest forecasted monthly demand after adjustment for load served under IR, FPT, and PTP contracts. The IR, FPT, and PTP contract demands subtracted from the non-generating public utility's system load to forecast NCD and NT Base Charge billing determinants are taken from Appendix A.

The generating public utility forecast is based on load information contained in the Northwest Power Pool's Operating Program, December 1998, or the Pacific Northwest Loads and Resources Study (White Book), December 1998. The forecasted billing determinants for generating public utilities under the NT Base Charge and NCD rate exclude service to the customer's load that is served by internal generation or under IR, FPT, or PTP contracts. Appendix D, Table 2 contains generating public utility forecasted system loads and other information used to forecast billing determinants under both NT and NCD services, and to estimate internal generation. The contract demands subtracted from the generating public utility's system load to forecast NCD and NT Base Charge billing determinants are taken from Appendix A.

2.3.1.1 Network Rate Choice

The selection of Network transmission service for most customers is forecast from an analysis that determines the customer's least costly service. In general, a contract demand service (PTP or NCD) is less expensive for utilities with high load factors and little diversity from the total transmission system peak. NT service costs less than contract demand service for low load factor customers with system peaks that differ from the overall transmission system peak. For cost allocation purposes, it is important to distinguish between NT and contract demand service. However, PTP and NCD services are treated the same for cost allocation purposes. The forecast of customers' Network service is shown in Appendix E, Column B.

Nine transmission customers are assigned a Network service without regard to the results of the “choice analysis.” Their assignment is based on information from the customer directly or from the customer's transmission account executive. Fairchild Air Force Base, the City of Heyburn, and Port Townsend Paper are modeled as NT customers; Eugene Water and Electric Board and Tacoma City Light are modeled as NCD customers; and Douglas PUD, Grant PUD, and Klickitat PUD are modeled as PTP customers for network rate determination. Additionally, all PNGC utilities are assumed to take NT service.

Seattle City Light and Snohomish County PUD are shown as NCD customers in Table 4 even though they have PTP contracts that extend through the 2002 rate period. The assumption of NCD service is based on these utilities' interest in purchasing the Slice of the System power product offered by the PBL and the suitability of NCD service in handling an excess of resources over load.

2.3.2 Short-Term and Hourly Sales

The forecast of short-term sales is shown in Table 5. Daily and hourly sales on the Network and Southern Intertie are forecast using an average of the latest two historical years, FY 1998 and FY 1999. Average 1998 and 1999 OASIS reservations of monthly, weekly, and daily sales are used as the basis of the forecasted FY 2002 and 2003 daily sales. The historical monthly, weekly, and daily sales are converted to the Block 1 (first 5 days of a reservation) and Block 2 (day 6 and beyond of a reservation) sales to reflect the new rate structure. Hourly sales are taken directly from history for FY 1999 and from the excess of total schedules over total long-term plus short-term rights for FY 1998.

A downward adjustment is made to the forecast of short-term Southern Intertie sales to account for increases in long-term contract demands. Long-term contract demands on the Southern Intertie for the rate review period are 2.5 times what they were forecast in the 1996 rate case. Increases in long-term IS contract demands should result in a reduction of short-term sales. An amount equal to 44% of the increase in long-term IS contract demands between the FY 1998/1999 historical period and the forecast period is subtracted from FY 1998/1999 short-term sales to yield the forecast of short-term IS sales. The reduction in short-term IS sales due to increased long-term sales is shown in Table 5, lines 5.19 and 5.26; Southern Intertie short-term sales are reduced in Table 8, line 8.10, to calculate the IS-02 rate. Forty-four percent reflects the estimated sensitivity of PBL's Southern Intertie short-term transmission purchases to changes in their long-term transmission purchases during FY 1998. Appendix D, Table D3 shows the summary statistics supporting this estimated relationship.

2.3.3 Utility Delivery Loads

The billing determinants for the Utility Delivery Charge are developed by point of delivery. The Delivery Charge is applicable to loads being served over Utility Delivery facilities at voltages below 34.5 kV. Appendix C shows the utilities and points of delivery forecasted to be subject to the Utility Delivery Charge. In addition to the substations already sold, the forecast assumes that customers will purchase additional substations during the remainder of the current rate period. All but two of the utilities appearing in Appendix C are non-generating publics. *See* Appendix D for forecast information for the non-generating publics. Utility delivery points for Clark Public Utilities and Grant County PUD are estimated from recent billing information.

2.4 Rate Calculations

The FPT rate is calculated first and forecasted FPT revenues are subtracted from Network costs. Network costs adjusted for FPT revenues are allocated to the remaining Network services using a 1CP cost allocation methodology. Table 11 shows the cost allocation and calculation of the Base Charge for IR, NCD, PTP, and NT rates and the NT Load Shaping charge. The annual Base Charge is used to calculate PTP daily and hourly charges.

The Southern Intertie (IS) rate is based on Southern Intertie rate development cost and forecasted IS sales. The Montana Intertie (IM) rate is based on TBL's annual cost under the TGT rate, and the capacity of TBL's share of the facility. The IS and IM daily and hourly rates are calculated using the same methodology as that used for the PTP rate. The IS north-to-south rates are seasonally differentiated.

2.4.1 FPT Rate Calculation

The proposed FPT rate is calculated by increasing the 1996 FPT rates by a uniform percentage that reflects the increase in unit Network cost between the 1996 rate case and the 2002 rate case. *See* Table 6. The unit Network cost is calculated by dividing the Network cost by the Network use determined by a power flow analysis.

2.4.1.1 FPT Network Costs

To calculate the unit 1996 Network cost, the measure of Network costs from the 1996 rate case is the 5-year average Network "rate development cost." 1996 Final Transmission Rate Design Study, WP-96-FS-BPA-06, Table 3, line 3.37. The measure of Network cost for the 2002 rate period includes two elements: average 2002/2003 Network segment costs, and the portions of the revenue requirements of the two required Ancillary Services that are associated with Network use. Table 6, lines 6.6 -

6.9. The two required Ancillary Services associated with Network use are Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service. The Network-related Ancillary Services cost is determined by prorating each revenue requirement by the Network portion of each billing determinant.

2.4.1.2 **<u>Network Use</u>**

The forecast of annual transmission peak loading is the indicator of system use that is used to determine the Network unit cost. The transmission peak loading, the Total Transmission System Loading (TTSL), is the sum of power coming onto the TBL transmission system over connections with other control areas and from generation within the BPA Control Area. The TTSL is determined from a power flow study made for the winter peak hour of the test period. The power flows are simulations of peak load conditions for January 1997 and for January 2002. The January 1997 power flow was used to determine FPT Network flows in the 1996 rate case. The January 2002 power flow is based on current data and is used to determine TTSL for the 2002 rate period. The TTSL determined from the January 1997 power flow is 29,394 MW, and the TTSL from the January 2002 power flow is 29,564 MW. Table 6, line 6.3.

Assumptions for the 1997 and 2002 power flow studies are consistent with assumptions used in past rate filings. Loads and resources for January 1997 are based on BPA's "1996 Pacific Northwest Loads and Resources Study" published in December 1995. Loads and resources for January 2002 are based on load and resources data available in

1999. Individual public agency load forecasts developed by the TBL are based on historical information. The forecasts for IOUs and large generating public utilities are provided by the utilities. All DSI loads are included at full operating levels. Updated load and generation forecasts are incorporated if available.

The power flow study incorporates the following load, resource operation, and transmission system conditions: normal winter interchange schedules between the Pacific Northwest and other regions; all large thermal generation plants scheduled to be available are assumed to be operating; hydro generation forecasts assume approximately median water conditions; and the transmission system is operated as planned, with all lines in service.

2.4.1.3 Calculation of the FPT Rate Components

Table 6 shows the development of the scaling factor that is applied to the individual FPT-96 rate components to determine the FPT-02 rate. The unit Network cost calculated for the 1996 rate case is $0.994/kW/month, and for the 2002 rate case is $1.368/kW/month (line 6.10). The increase of the 2002 rate period unit cost over that for the 1996 rate period is 37.64% (line 6.11), which is applied to each FPT-96 rate component to calculate FPT-02 rates. The resulting FPT rate components are shown in Table 13.

2.4.2 <u>Network Rate Calculations</u>

After the FPT rate is calculated and revenue is forecasted, the remaining Network rates (IR, PTP, NCD, and NT) are calculated using a 1CP methodology. *See* Table 7. First, forecasted FPT revenues are subtracted from the Network rate development cost (Table 3) to calculate the costs to be recovered from the remaining Network rates (line 7.3). The Base Charge (IR, PTP, NCD, NT) of $13.58/kW/year is calculated by dividing the adjusted Network cost by the sum of all forecasted Network sales: long-term and short-term, firm and nonfirm PTP demands; IR and NCD demands; and a 1CP measure of NT Base Charge demands. Short-term daily and hourly sales are the adjusted "rate design megawatts" addressed below.

The daily Block 1 (first five days of a reservation) and Block 2 (day 6 and beyond of a reservation) rates, and the hourly rate are then calculated. The Block 1 daily rate is calculated by dividing the annual rate by 365 days and 5/7, and the Block 2 daily rate is calculated by dividing the annual rate by 365 days. The hourly rate is calculated by dividing the annual rate by the number of peak hours in the year (5 days per week, 16 hours per day).

The forecast of daily Block 1 sales and hourly sales on Table 5 are adjusted to calculate rates. The rates for short-term service are factored into the calculation of the annual contract demand rates by artificially increasing the short-term sales in the divisor. The calculation of these "rate design MWs" is shown in Table 7 (lines 7.11 and 7.13) for the Network (and Table 8 (lines 8.11 and 8.13) for the Southern Intertie). The forecasted

Block 1 daily sales are increased by 7/5 because the rate is 7/5 higher than it would be if the annual rate were simply divided by 365. Similarly, the hourly sales are multiplied by 7/5 times 24/16ths.

These contract demand rates are then applied to forecasted sales. The resulting revenue is subtracted from the adjusted Network cost to determine the cost basis of the NT Transmission Load Shaping Charge. This remaining Network cost, $16.671 million, is divided by the forecasted Load Shaping sales, 4,266 MW per year, to calculate the NT Load Shaping charge of $0.326/kW/month.

2.4.3 Intertie Rate Calculations

2.4.3.1 Southern Intertie Rate Calculation

The IS-02 rate is seasonally differentiated for north-to-south use, with the winter rate set equal to 75% of the summer rate. The summer season is defined as April through September and the winter season is October through March. Table 8 shows the development of the IS rates. Appendix I shows the basis for the seasonal differentiation and describes the methodology used to set the IS rate. Rate development Southern Intertie costs are divided by all projected sales on the Federal portion of the Southern Intertie to compute the annual IS rate of $13.88/kW/year, or $1.157/kW/month. This rate is the basis for the South to North rate, which is not seasonally differentiated. Daily and hourly rates are computed using the same method used to calculate the PTP daily and hourly rates described in section 2.4.2.

To calculate the seasonal rates for North to South service, the first step is to subtract the revenues forecast for South to North sales (Table 8, line 8.20) from the adjusted Southern Intertie revenue requirement. In order to set the winter rate equal to 75% of the summer rate, the revenues from the winter rate (winter sales multiplied by the summer rate multiplied by 75%) plus revenues from summer sales at the summer rate must equal the net revenue requirement. The summer price is derived by dividing the net revenue requirement by the sum of all summer sales and 75% of winter sales (Table 8, line 8.25). The summer north-to-south rate is $1.299/kW/month. Finally, winter rates are computed by taking 75% of the summer rate. The winter north-to-south rate is $0.974/kW/month. The daily and hourly rates are computed using the same method described in section 2.4.2.

2.4.3.2 <u>Montana Intertie Rate Calculation</u>

The Montana Intertie rate for long-term service, $14.87/kW/year, equals TBL's payment under the TGT rate for the Montana Intertie facilities divided by TBL's capacity allocation of 185 MW. The IM daily and hourly rates are calculated using the same method described in section 2.4.2. *See* Table 9.

2.4.4 Eastern Intertie Rate Calculation

The IE rate for nonfirm service is developed by dividing the Eastern Intertie segment cost by the forecast amount of Colstrip energy. *See* Table 9. The proposed IE-02 rate cap is 1.38 mills/kWh. This rate is set pursuant to the Montana Intertie Agreement.

2.4.5 Delivery Charge Calculations

2.4.5.1 Utility Delivery Charge

The Utility Delivery Charge is charged to customers taking delivery of power, either Federal or non-Federal, over transformers that are in the Utility Delivery Segment. The calculation of the rate is shown in Table 10. The Utility Delivery charge of $1.299/kW-mo. equals the adjusted Utility Delivery segment cost of $10.059 million divided by the load on Utility Delivery facilities (645 MW) determined in Appendix C. Consistent with the 2002 Power Rate Case Initial Proposal, the calculation of the Utility Delivery Charge assumes that no funds were received from the PBL.

2.4.5.2 DSI Delivery Charge

The DSI Delivery Charge is designed to recover the entire cost of the DSI Delivery segment from the DSI customers taking service over delivery facilities. The forecast of revenues from application of UFT charges to DSI Delivery facilities (Appendix G) results in a revenue shortfall when compared to the DSI Delivery segment cost. Therefore, to recover the entire cost of the DSI Delivery segment, the DSI Delivery charge includes an adjustment factor that is applied to each DSI's UFT charge. The adjustment factor of 1.197 is the total DSI Delivery segment costs divided by the expected UFT revenues. Calculation of the adjustment factor is shown in Table 10. The expected UFT revenues are based on projected increases in O&M costs and investment amounts as shown in Appendix G.

2.4.6 <u>Ancillary Service and Control Area Service Rate Calculations</u>

Rates are calculated for all Ancillary Services and Control Area Services with the exception of the Energy Imbalance/Generation Imbalance Services. Under these Imbalance services, energy return is required if customers stay within an imbalance band; otherwise, customers pay a penalty rate. Control Area Service rates for Regulation and Frequency Response Service, and Spinning and Supplemental Operating Reserve Services are the same as the Ancillary Service rates. CAS rates allow a party to satisfy all of its reliability obligations for resources or loads in the BPA Control Area.

2.4.6.1 <u>Cost</u>

The Ancillary Service rates are based on the adjusted revenue requirement for Ancillary Services in Table 3. These net revenue credit to the Ancillary Services revenue requirement is segmented among the six Ancillary Services. Table 11, columns B and C. For customers taking FPT service, the two required services of Scheduling, System Control and Dispatch (Scheduling) and Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) have not been unbundled. Therefore, the revenue requirements for these two services are further adjusted to account for the portion of the revenue requirement being recovered through the FPT rates. Table 11, columns D and E.

2.4.6.2 <u>Scheduling, System Control and Dispatch and Reactive Supply and Voltage Control from Generation Sources Rate Calculations</u>

Scheduling Service and Generation Reactive Service is charged to all users of the Network and Interties on the same basis as their transmission service. The billing determinant is all forecasted long-term and short-term use of the Network and Interties, excluding FPT use. These are the same loads that are used to calculate the IR, PTP, NCD, NT Base, and IS rates. For the Generation Reactive rate, the total billing determinant is also adjusted for forecasted self-supply of Generation Reactive. Self-supply of Generation Reactive is limited to resources that meet specified criteria, and is estimated at 1,125 MW. Table 11, line 11. The rate design for these two Ancillary Service rates for PTP transmission service is the same as that used for the PTP transmission service rates—PTP, IS, and IM--so that these rates can be applied to all long-term and short-term uses of the transmission system. *See* section 2.4.2 for a description of the PTP rate design.

2.4.6.3 <u>Regulation and Frequency Response Rate Calculation</u>

All Transmission Customers serving load in the BPA Control Area must purchase Regulation and Frequency Response Service. The Billing Factor for this service is energy delivered to load in the BPA Control Area. The forecasted BPA Control Area load for the 2002-2003 rate period is the average 1998 and 1999 BPA Control Area load, escalated at 2% a year. The 2% escalation is based on the increase between 1998 and 1999 Control Area loads. *See* Table 11, lines 18-19. Dividing the average Regulation and Frequency Response rate development cost of $15.868 million by the average Control Area load of 6,109 MW results rate in a rate of 0.3 mills/kilowatthour.

2.4.6.4 <u>Operating Reserves Rate Calculation</u>

All Transmission Customers serving firm load obligations from generation in the BPA Control Area must purchase operating reserves. The amount of required operating reserves is based on the reserve obligation associated with resources in the BPA Control Area. The BPA Control Area reserve obligation of 525 average MW is calculated based on the capacity of Federal System resources: 464 MW is 5% of hydroelectric generation (9280 MW), and 61 MW is 7% of non-hydroelectric generation (870 MW). The total reserve obligation is split evenly between Spinning and Supplemental reserve obligation. This obligation is determined by applying the standards established by the Western Systems Coordinating Council (WSCC) "Minimum Operating Reliability Criteria" (MORC), and the Northwest Power Pool (NWPP) Reserve Sharing program for control areas. *See* Table 11, lines 11.13-11.17. The Spinning and Supplemental Reserves rates of 8.27 mills/kilowatthour are calculated by dividing the Operating Reserve revenue requirements by the BPA Control Area reserve obligations.

3. TRANSMISSION AND ANCILLARY SERVICE RATE SCHEDULES

3.1 Formula Power Transmission Rates (FPT-02.1 and FPT-02.3)

The FPT-02.1 and FPT-02.3 rates are available for firm transmission of non-Federal power on the Network for both full-year and partial-year service. Nonfirm wheeling may not be done at the FPT rate. The embedded cost FPT rates include a distance component for transmission lines and various transformation and terminal charges. The FPT-02.1 rate is used for contracts allowing annual rate adjustments. The FPT-02.3 rate is used for contracts that allow a rate change only once every 3 years. Both FPT rates are adjusted in this rate proposal and have the same charges. FPT service does not allow assignment of Transmission Demand to third parties. The FPT rates apply only to existing contracts.

The FPT rate schedules also include the Power Factor Penalty Charge, the Failure to Comply Penalty Charge, and notice regarding ancillary services. *See* section 3.11 for further discussion of these provisions.

3.2 Integration of Resources Rate (IR-02)

The proposed IR-02 rate is a "postage stamp" rate (independent of distance) consisting of a monthly demand charge. The IR rate applies to existing agreements for the transmission of non-Federal power. Such agreements are used to integrate multiple resources and transmit power to multiple points of delivery at the customer’s system. Nonfirm wheeling from alternate Points of Integration, up to the contractually specified total Transmission Demands, may be done at the IR rate, subject to the availability of transmission capacity. Contractually specified IR Transmission Demands for Points of Integration are based on the annual peak output of a generating resource or annual peak demand in a purchase power agreement. The billing factor for the embedded cost IR demand charge is Total Transmission Demand. Upon agreement, the IR rate may be applied to other services, such as access to an intertie. IR service does not allow assignment of Transmission Demand to third parties.

BPA proposes to continue the Short Distance Discount (SDD) which decreases the IR rate by up to 40 percent when the distance between Point of Integration and Point of Delivery is less than 75 circuit miles. This is an exception to the postage-stamp demand charge for transactions that customers can demonstrate use only specific FCRTS facilities for a distance of less than 75 circuit miles. This demonstration is made as part of the process of negotiating an agreement that uses this rate schedule. The SDD rate is determined by multiplying the IR Base rate by the following formula:

$$.6 + \frac{(.4 \times \text{transmission distance})}{75 \text{ miles}}$$

The IR rate schedule also includes the Power Factor Penalty Charge, the requirement to purchase Scheduling and Generation Reactive ancillary service, the Delivery Charge, and the Failure to Comply Penalty Charge. *See* section 3.11 for further discussion of these provisions.

3.3 Network Integration Rate (NT-02)

The proposed NT-02 rate applies to Transmission Customers taking Network Integration Service under the Open Access Transmission Tariff. NT Service provides transmission service for a customer's retail load. Charges for use of the Network include a Base Charge and a Transmission Load Shaping Charge. The NT Base Charge is billed on a net load basis: it is applied each month to the customer's total load that occurs on the hour of the Monthly Transmission Peak Load (MTPL) less Declared Customer-Served Load (Declared CSL). Declared CSL is the monthly amount of capacity load the customer declares it will serve on a firm basis without using NT transmission service. The Actual CSL, the amount of the customer's load that is actually served without using NT service, must be greater than 60 percent of the Declared CSL on average over all the Heavy Load Hours (HLH). If the customer fails to maintain its Actual CSL at this level, it will be billed for its total retail load on the hour of the MTPL. In addition, if the Actual CSL is less than the Declared CSL on the hour of the MTPL, the NT Unauthorized Increase Charge is applied to the difference between the Actual and Declared CSL.

The Transmission Load Shaping Charge is applied to the customer's Network Load on the hour of the MTPL. This Charge recovers the cost of having transmission available to serve the customer's annual peak load.

The NT-02 rate schedule also includes a variety of adjustments, charges and other rate provisions, including: a requirement to purchase Scheduling and Generation Reactive ancillary services; the Delivery Charge; the NT Unauthorized Increase Charge discussed above; the Power Factor Penalty Charge; the Redispatch Adjustment for Accepted Bids and the Redispatch Charge when TBL implements redispatch procedures; the Failure to Comply Penalty Charge; notice of TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. Finally, the rate schedule provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate and a Metering Adjustment for Points of Delivery that do not have hourly demand meters.

3.4 Network Contract Demand Rate (NCD-02)

The proposed NCD-02 rate applies to Transmission Customers taking Network Contract Demand Service under the Open Access Transmission Tariff. The NCD-02 rate applies to Network transmission service on a long-term contract path basis. NCD service may be used to serve native load and transactions with third parties over Network (with access to the Interties) and Delivery facilities. The NCD rate schedule provides a monthly rate for long-term service. The NCD demand charge is applied to the sum of Transmission Demands at PODs. NCD customers must specify Network Resources in their service agreement, but are not charged on them. NCD service allows flexibility to use Network Resources not specified in their service agreements on a nonfirm basis at no additional cost. In addition, NCD service allows firm service at secondary PODs, on an as-available basis.

The NCD-02 rate schedule also includes a variety of adjustments, charges and other rate provisions, including a requirement to purchase Scheduling and Generation Reactive ancillary services; the Delivery Charge; the Power Factor Penalty Charge; the NCD Unauthorized Increase Charge; the Redispatch Adjustment for Accepted Bids and the Redispatch Charge when TBL implements redispatch procedures; the Failure to Comply Penalty Charge; the Reservation Fee; notice of TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. Finally, the rate schedule provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.5 Point-to-Point Rate (PTP-02)

The proposed PTP-02 rate includes rates for Long-Term Firm service, and daily and hourly firm and nonfirm service on the Network. Under the 1996 rates, PTP service on the Network is available under three rate schedules: the PTP rate for firm service; the Reserved Nonfirm (RNF) rate for short-term nonfirm service; and the Energy Transmission (ET) rate for hourly nonfirm service. These three 1996 rate schedules are combined into one rate schedule for 2002. The PTP-02 rate schedule includes all rates for all PTP services on the Network.

The proposed PTP-02 rate applies to Network transmission service on a contract path basis. PTP service may be used to serve native load and transactions with third parties over Network (with access to the Southern Intertie) and Delivery facilities. The PTP rate schedule includes a monthly rate for long-term service, and downwardly flexible daily and hourly rates that apply to both firm and nonfirm service. Reservations for short-term service are made for consecutive days for daily service, or consecutive hours for hourly service.

Two rates for daily service are provided--one for the first five days of a reservation, and the other for the remaining days of the reservation. For reservations with a duration greater than five days, one charge will be applied to the first five days of the reservation, and a second charge to the remaining days of the reservation. One hourly rate applies to all hours of a reservation for hourly service.

The PTP-02 rate schedule continues to include a Short-Distance Discount which is very similar to the SDD in the IR rate. The PTP rate schedule also includes: a requirement to purchase Scheduling and Generation Reactive ancillary services; the Delivery Charge; the Power Factor Penalty Charge; an Unauthorized Transmission Increase charge; the Reservation Fee; the Failure to Comply Penalty Charge; a credit for interruption of daily nonfirm service, notice of BPA's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.11 for further discussion of these provisions. Finally, the rate schedule provides notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.6 Point-to-Point Intertie Service: Southern Intertie Rate (IS-02) and Montana Intertie Rate (IM-02)

The IS-02 and IM-02 rate schedules are applicable to all transmission service on the Southern Intertie and Montana Intertie, respectively, under the terms and conditions of the PTP tariff. In addition, the IS rate schedule applies to transmission contracts for Southern Intertie service in effect prior to October 1, 1996. The IM rate provides for service over BPA's 185 MW of Montana Intertie capacity rights. The IS and IM rate schedules include rates for long-term firm service, and daily and hourly firm and nonfirm service. The daily and hourly firm and nonfirm rates are caps that are downwardly flexible.

Similar to the PTP-02 rate schedule, the IS-02 and IM-02 rate schedules provide blocked rates for daily firm and nonfirm service. The IS rate schedule also includes rates for north-to-south service and rates for south-to-north service. The north-to-south IS rates are seasonally differentiated with rates for the April through September summer period and rates for the October through March winter period.

The IS and IM rate schedules also include: the requirement to purchase certain ancillary services; a credit for interruption of daily nonfirm service; the Reservation Fee; the Power Factor Penalty Charge; an Unauthorized Transmission Increase charge; the Failure to Comply Penalty Charge; notice of BPA's intent to charge incremental cost rates under specified conditions, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.1X for further discussion of these provisions. Finally, the rate schedules provide notice regarding Direct Assignment Facility costs which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

3.7 <u>Townsend-Garrison Transmission Rate (TGT-02) and Eastern Intertie Rate (IE-02)</u>

The proposed TGT and IE rates are based on provisions of the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended). The TGT-02 rate recovers the cost of the Townsend-Garrison facilities. The IE-02 rate is available to parties to the Montana Intertie Agreement for nonfirm transmission service on the Eastern Intertie on the portion of the Eastern Intertie capacity above BPA's firm transmission rights. The stated rate, an energy charge, sets the cap and is downwardly flexible. Revenue from these transactions is treated as a revenue credit against the TGT rate.

3.8 <u>Use-of-Facilities Transmission Rate (UFT-02)</u>

Wheeling transactions over specifically identified facilities occur under the UFT-02 formula-based rate. The UFT rate schedule provides for UFT charges on a sole-use basis, a common practice for establishing UFT charges when only one customer uses specified facilities. In addition, the Power Factor Penalty Charge and notice regarding ancillary services is included in the rate schedule.

3.9 <u>Advance Funding Rate (AF-02)</u>

This rate schedule allows TBL to collect the capital and related costs of specified TBL-owned transmission facilities through advance funding when such advance payment is provided for in an agreement with a customer. Such facilities may include interconnection and resource integration facilities, and FCRTS upgrades, reinforcements, and replacements. Following commercial operation of the specified facilities, a true-up of estimated costs with actual costs would occur. Application of this rate shall be pursuant to FERC transmission pricing policy.

3.10 <u>Ancillary Services and Control Area Service Rate Schedule (ACS-02)</u>

The proposed ACS-02 rate schedule includes rates for the six required Ancillary Services and four Control Area services. All transmission contract holders must satisfy the reliability requirements associated with their energy transactions, whether energy is delivered into, out of, within, or through the BPA Control Area. Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. TBL, as the Transmission Provider, is required to provide, and Transmission Customers are required to purchase, the Ancillary Services of Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control from Generation Sources. TBL is required to offer to provide the following Ancillary Services to Transmission Customers serving load or integrating generation within the BPA Control Area: Regulation and Frequency Response; Energy Imbalance; Operating Reserve – Spinning; and Operating Reserve - Supplemental. The Transmission Customer serving load or integrating generation within the BPA Control Area is required to acquire these Ancillary Services, whether from the TBL, from a third party, or by self-supply.

Control Area Service rates apply to transactions in the BPA Control Area for which the reliability obligations have not been met through Ancillary Services or some other arrangement. The four CAS rates are Load Regulation and Frequency Response Service; Generation Imbalance Service; Operating Reserve -- Spinning Reserve Service; and Operating Reserve – Supplemental Reserve Service. To the extent that resources or loads in the BPA Control Area do not otherwise satisfy the reliability obligations that their energy transactions impose on the BPA Control Area, Control Area Services must be purchased from TBL.

All rates in the ACS-02 rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA Section 212.

3.10.1 <u>Scheduling, System Control, and Dispatch (Scheduling) Service</u>

Scheduling Service is necessary to the provision of basic transmission service within every control area. This service can be provided only by the operator of the control area in which the transmission facilities used are located. This is because the service is to schedule the movement of power through, out of, within, or into the control area. Scheduling Service also includes the dispatch of generating resources to maintain generation/load balance and maintain security during the transaction.

The rates in section II.A of the ACS-02 rate schedule apply to all transmission transactions under the Open Access Transmission Tariff and IR service agreements. Transactions on the Network and Interties are each charged separately for this service on the same basis as they are charged for their transmission service: transmission demands for PTP (Network, Southern Intertie, Montana Intertie), NCD, and IR customers; and the Base Charge billing factor for NT customers. The rate charges are structured to correspond to the various transmission services available – long-term and short-term firm and nonfirm service. Thus, the Scheduling charge for long-term firm service would apply to NT, NCD, IR, and long-term PTP service. The short-term firm and nonfirm Scheduling charges would apply to short-term firm and nonfirm PTP transmission service. All charges are downwardly flexible; any discounts would be offered consistent with section II.H of the GRSPs.

3.10.2 Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service

Generation Reactive Service is the provision of reactive power and voltage control by generating facilities under the control of the TBL. This service is necessary to the provision of basic transmission service within every control area.

The rates in section II.B of the ACS-02 rate schedule apply to all transmission transactions under the Open Access Transmission Tariff and IR service agreements. The description of the Scheduling Service rate schedule, above, also applies to the Generation Reactive rate schedule. However, the Generation Reactive Service rate includes a billing factor provision that recognizes that under some circumstances this Service may, in part, be self-provided.

3.10.3 Regulation and Frequency Response (Regulation) Service

Regulation Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the TBL. The TBL must offer this service when the transmission service is used to serve load within the BPA Control Area. The transmission customer must either purchase this service from the TBL or make alternative comparable arrangements to satisfy its Regulation Service obligation. Customers may be able to satisfy the Regulation Service obligation by providing generation with automatic generation control capabilities to the TBL.

The Regulation Service rate in section II.C of the ACS-02 rate schedule provides an energy charge to be applied to the customer's load in the BPA Control Area. The charge is downwardly flexible; any discounts would be offered consistent with section II.H of the GRSPs.

3.10.4 Energy Imbalance Service

Energy Imbalance Service is for transmission within and into the BPA Control Area to serve load in the Control Area. Energy Imbalance represents the deviation between the scheduled and actual delivery of energy to a load in the BPA Control Area over a single hour.

All Transmission Customers serving load in the BPA Control Area are subject to charges for Energy Imbalance. The Energy Imbalance rate in section II.D of the ACS-02 rate schedule establishes an imbalance deviation band. If deviations between customers' loads and schedules stay within the imbalance deviation band, customers are only required to return the energy at a later time. A deviation account is used to sum the positive and negative deviations from schedule over all schedule hours. Once a month this account must be settled (brought to zero). TBL will designate the time and amounts to be delivered to accomplish the settlement. The customer will arrange for and schedule the delivery.

If actual loads are greater than schedules by more than the greater of 2 MW or 1.5%, a penalty rate applies. For these deviations in excess of the energy imbalance band, the rate is the higher of 100 mills per kWh or 110% of BPA's incremental cost. BPA's incremental cost will be a market-based rate determined by an hourly energy index in the PNW. If actual loads are less than schedules, by more than 2 MW or 1.5%, the customer will receive a credit for the excess energy equal to 90% of the market rate, provided that the deviation was not an Intentional Deviation and the Federal System was not in Spill Condition during the month.

3.10.5 Operating Reserve -- Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. TBL must offer this service when the transmission service is used to serve firm load from generation located in the BPA Control Area. The Transmission Customer must either purchase this service from TBL or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer’s obligation is determined consistent with North American Electric Reliability Council (NERC), WSCC, and Northwest Power Pool criteria.

The Spinning Reserve Service rate, section II.E of the ACS-02 rate schedule, includes two components. The first component is an energy charge that is applied to the customer's Spinning Reserve Requirement. This rate of 8.27 mills/kWh recovers the cost of having generation available to respond to a system contingency. The Spinning Reserve Requirement is determined, based on current WSCC and NWPP standards, as 2.5% of the hydroelectric generation and 3.5% of the non-hydroelectric generation located in the BPA Control Area used to serve the transmission customer's firm load. The Spinning Reserve Requirement will be adjusted when and if WSCC and NWPP standards change. The Spinning Reserve charge is downwardly flexible; any discounts would be offered consistent with section II.H of the GRSPs.

The second Spinning Reserve Service rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by the TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

3.10.6 <u>Operating Reserve -- Supplemental Reserve Service</u>

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. The TBL must offer this service when the transmission service is used to serve firm load from generation located in the BPA Control Area. The Transmission Customer must either purchase this service from the TBL or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission customer's obligation is determined consistent with NERC, WSCC and Northwest Power Pool criteria.

The Supplemental Reserve Service rate, section II.F of the ACS-02 rate schedule, is the same as the Spinning Reserve Service rate described above with one exception. The Billing Factor for the Supplemental Reserve Requirement includes an additional factor accounting for power scheduled into the BPA Control Area that is interruptible on 10 minute's notice, consistent with current WSCC and NWPP standards.

3.10.7 CAS Regulation and Frequency Response Service

The Control Area Service Regulation and Frequency Response is the same technical service, at the same rate, as the Ancillary Service so named. The difference is, the Control Area Service is offered to loads in the BPA Control Area that may not be taking BPA basic transmission service. Loads served by generation "behind the meter" are an example. Unless that load is receiving Regulation and Frequency Response Service to the same quality standards BPA uses for its service from the "behind the meter" generation, the BPA Control Area is in fact providing the service to that load. Reliability standards established by WSCC applied to the BPA Control Area result in BPA operating sufficient regulating reserves to cover the requirements of all Control Area load. Each load in the Control Area must purchase an amount to cover the obligation it imposes upon the Control Area. To the extent that loads are not otherwise receiving this service, it must be purchased from the BPA Control Area. The ACS-02 rate schedule identifies the energy charge to be applied to load in the BPA Control Area.

3.10.8 CAS Generation Imbalance Service

Generation Imbalance Service provides or absorbs energy to meet the difference between scheduled and actual generation delivered to the BPA Control Area from generators located in the BPA Control Area. All generators in the BPA Control Area are subject to charges for Generation Imbalance Service. The Generation Imbalance Service rate in section III.B of the ACS-02 rate schedule establishes an imbalance deviation band. If the difference between a generator's schedule and its delivery stays within the imbalance deviation band, the only requirement is return of energy at a later time. A deviation account is used to sum the positive and negative deviations from schedule over all schedule hours. Once a month this account must be settled (brought to zero). TBL will designate the time and amounts to accomplish the settlement. The generator will arrange for and schedule the delivery.

If actual generation is less than schedule by more than 2 MW or 1.5%, a penalty rate applies. For these deviations in excess of the generation imbalance deviation band, the rate is the higher of 100 mills/kWh or 110% of BPA's incremental cost. BPA's incremental cost will be a market- based rate determined by an hourly energy index in the PNW. If actual generation exceeds the schedule by more than 2 MW or 1.5%, the customer will receive a credit for the excess energy equal to 90% of the market rate, provided that the deviation was not an Intentional Deviation and the Federal System was not in Spill Condition during the month.

3.10.9 <u>CAS Operating Reserve -- Spinning Reserve Service</u>

The Control Area Service Operating Reserve -- Spinning Reserve Service is the same technical service, at the same rate, as the Ancillary Service so named. The difference is that the Control Area Service is taken by generators in the BPA Control Area which may not have a Transmission Contract with BPA, but have energy transactions which impose a spinning reserve obligation on the BPA Control Area. The generator's obligation is determined consistent with NERC, WSCC, and Northwest Power Pool criteria. To the extent that Spinning Reserve Service is not otherwise provided to cover the generator's

Spinning Reserve obligation (through Ancillary Service purchases or self-supply, for example), the Control Area Service is provided and must be purchased.

The Spinning Reserve Service rate, section III.C of the ACS-02 rate schedule, includes two components. The first component is an energy charge that is applied to the customer's Spinning Reserve Requirement. This rate of 8.27 mills/kWh recovers the cost of having generation available to respond to a system contingency. The Spinning Reserve Requirement is determined, based on current WSCC and NWPP standards, as 2.5% of the hydroelectric generation and 3.5% of the non-hydroelectric generation located in the BPA Control Area used to serve the firm load responsibility. The Spinning Reserve Requirement will be adjusted when and if WSCC and NWPP standards change.

The second Spinning Reserve Service rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by the TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

3.10.10 <u>CAS Operating Reserve -- Supplemental Reserve Service</u>

The Control Area Service Operating Reserve -- Supplemental Reserve Service is the same technical service, at the same rate, as the Ancillary Service so named. The difference is that the Control Area Service is taken by generators in the BPA Control Area which may not have a Transmission Contract with BPA, but have energy transactions which impose a supplemental reserve obligation on the BPA Control Area. The generator's obligation is determined consistent with NERC, WSCC, and Northwest Power Pool criteria. To the extent that Supplemental Reserve Service is not otherwise provided to cover the generator's Supplemental Reserve obligation (through Ancillary Service purchases or self-supply, for example), the Control Area Service is provided and must be purchased.

The Supplemental Reserve Service rate, section III.D of the ACS-02 rate schedule, is the same as the Spinning Reserve Service rate described above with one exception. The Billing Factor for the Supplemental Reserve Requirement (section II.F.2.a) includes an additional factor accounting for any power scheduled into the BPA Control Area that is interruptible on 10 minute's notice, consistent with current WSCC and NWPP standards.

3.11 Other Charges and Provisions

3.11.1 Delivery Charge

The Delivery Charge, section II.A of the GRSPs, is applied to deliveries of power over Delivery facilities as defined by the DSI Delivery and Utility Delivery segments. The Delivery Charge includes separate rates for service over DSI Delivery and Utility Delivery facilities.

The DSI Delivery charge uses the UFT-02 rate increased by a factor of 1.197 to determine the rate. If the DSI Delivery facilities serve only a DSI load and no other

TBL customers, the UFT charge will be a sole use charge; i.e., the total annual cost associated with the facilities determined in accordance with section III.B.1 of the UFT-02 rate schedule. If the DSI Delivery facilities serve more than one customer, the UFT charge will be based on the total annual cost associated with the facilities prorated between or among the customers using the delivery facilities in accordance with section III.B.2 of the UFT-02 rate schedule. The annual cost (total or prorated) will be divided by 12 and multiplied by a factor of 1.197 to calculate the monthly DSI Delivery Charge.

The Utility Delivery Charge continues to be an average cost charge that is assessed on the demand on the Utility Delivery facilities on the hour of the Monthly Transmission Peak Load.

3.11.2 Power Factor Penalty Charge

TBL proposes to continue charging customers for their excessive reactive power requirements. The Power Factor Penalty Charge, found in section II.C. of the GRSPs and included in TBL's transmission rate schedules, will replace the current Reactive Power Charge in the 1996 rate schedules. The customer will be billed directly for measured quantities of reactive demand which fall outside a specified deadband. The deadband equals 25% of the highest real power demand (based on a 0.97 power factor) at the Point of Interconnection (POI) during the billing month. The Power Factor Penalty Charge applies only to lagging reactive demand during Heavy Load Hours and only to leading reactive demand during Light Load Hours. An eleven-month ratchet will be applied to the demand charge. There will be separate ratchets for leading and lagging reactive demand.

The Power Factor Penalty Charge is applied hourly to each POI between TBL and parties interconnected to the FCRTS. A customer taking power under multiple rate schedules will pay for its reactive power requirements at each point as if it were taking service under only one rate schedule.

The purpose of the Power Factor Penalty Charge is to provide an incentive to minimize preventable reactive flows at interconnections with the FCRTS. The demand charge for lagging reactive power is based on the installed cost of capacitors; the demand charge for leading reactive power is based on the installed cost of reactors. The proposed rate is the per unit installed cost of reactors and capacitors, and is calculated by dividing the annual cost of the respective facilities by the installed capacity to get cost per kVAr. This is then multiplied by the penalty factor of two. Calculation of the Power Factor Penalty Charge is shown in Appendix K.

3.11.3 <u>Redispatch Adjustment for Accepted Bids</u>

This provision, found in section II.E of the GRSPs, recognizes the obligation of parties whose decremental redispatch bids have been accepted, to pay TBL the total cost associated with the accepted bid. It also recognizes TBL's obligation to promptly pay parties for their accepted incremental bids. The Redispatch Adjustment is included in the NT and NCD rate schedules because NT and NCD customers are required to submit decremental bids for redispatch procedures. However, it is applicable to any party that submits incremental or decremental bids for redispatch. On accepted bids, the credit or charge will appear on the party's monthly transmission bill. However, if a party is not otherwise a TBL customer, TBL will pay the party for the accepted incremental bid within 30 days following the end of the month that the redispatch occurred.

3.11.4 <u>Redispatch Charge</u>

The Tariff (sections 37.3 and 44.3) requires each NT and NCD customer to bear a proportionate share of total redispatch cost based on the Redispatch Mechanism. The Redispatch Charge is a formula rate that charges each NT and NCD customer the net cost of implementing redispatch procedures. The net cost of redispatch is determined for each hour that redispatch procedures are implemented and allocated to customers based on their use of the congested path for that hour.

3.11.5 <u>Failure to Comply Penalty Charge</u>

The Failure to Comply Penalty, found in section II.B of the GRSPs, will be assessed to parties that fail to properly respond to a curtailment, redispatch, or load shedding order from TBL. This includes, without limitation, failure of chosen incremental and decremental bidders to adjust their generation as part of TBL’s redispatch mechanism; failure of generators in the BPA Control Area or which directly connect to the FCRTS to change generation when directed to do so by TBL; failure to shed load in accordance with the Tariff or any applicable agreements between TBL and the party; failure to curtail a schedule; and failure to respond to TBL operational orders in the time period specified by regional reliability criteria.

3.11.6 Unauthorized Increase Charge

For rate schedules under the PTP tariff (PTP, IS, and IM), the NT tariff (NT), and the NCD tariff (NCD), TBL proposes to assess an Unauthorized Increase Charge (UIC) if customers exceed their transmission demands. The UIC is set at half the annual PTP rate, or $6.79 per kW per month. The UIC would not be applied if the transmission customer arranges for short-term transmission prior to exceeding contracted amounts.

For NCD service, TBL will calculate unauthorized increases at PODs and at Network Resources; the higher of which will be the billing factor for the UIC. The POD unauthorized increase is calculated the same way as the UIC for PTP services. The unauthorized increase at Network Resources will be based on a comparison of actual demands at Network Resources to the customer's total Transmission Demands at PODs. Measurement of actual demands for one-way dynamically scheduled Network Resources will be based on a 10-minute moving average measure, and for all other Network Resources will be based on the 60-minute integrated demands or transmission schedules.

The UIC in the NT rate schedule is applied if the customer's Actual Customer-Served Load is less than its Declared CSL on the monthly billing hour.

3.11.7 Reservation Fee

The Reservation Fee, found in section II.G in the GRSPs, is included in the NCD, PTP, IS, and IM rate schedules. The Reservation Fee is applicable to NCD and PTP Transmission Customers who want to postpone the commencement of service pursuant to sections 29.5 or 38.7 of the Open Access Transmission Tariff for up to five years. The Reservation Fee is a nonrefundable fee equal to one month's charge for each year or fraction of a year for which the customer chooses to postpone service. If TBL receives a request for service over the same transmission path and there is insufficient capacity to accommodate both, the original transmission customer may begin paying the full monthly transmission rate or release the reserved capacity.

3.11.8 Incremental Cost Rates

TBL provides notice in most of the firm rate schedules that requests for new or increased firm transmission service that would require TBL to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates. Such rates would be developed pursuant to section 7(i) of the Northwest Power Act. TBL will apply the incremental cost rate consistent with FERC’s “or” pricing: the higher of embedded cost or incremental cost would be charged, but not the sum of the two.

3.11.9 Rate Adjustment Due to FERC Order Under FPA §212

This provision is included in the NT, PTP, RNF, ET, IS, IM, and ACS rate schedules, which are designed to offer Tariff service comparable to BPA's use of the system. These rate schedules, after review by FERC, may be modified to satisfy statutory standards for FERC-ordered transmission service. For customers taking non-FERC-ordered transmission service, the modifications shall be effective only prospectively from the date of the final FERC order that grants final approval of the rate schedule for FERC-ordered transmission.

TABLES

Table 1
Transmission Revenue Requirements
($000)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		TBL	Generation		Delivery		Intertie		Ancillary
		Total	Integration	Network	Utility	Industry	Southern	Eastern	Services
	FY 2002								
1. 1	Gross Plant......................................	4,764,523	60,378	3,467,647	67,084	59,320	684,369	123,667	302,058
1. 2	Lines......................................	2,213,732	16,557	1,889,069	3,270	1,534	204,431	98,870	
1. 3	Stations...................................	2,248,733	43,821	1,578,578	63,814	57,786	479,938	24,797	
1. 4	Net Plant..	3,084,547	49,815	2,227,434	55,629	48,859	416,739	80,021	206,050
1. 5	Operating Expenses.............................	228,439	2,399	149,250	4,450	2,521	25,165	2,019	42,635
1. 6	Generation Inputs...............................								
1. 7	Ancillary Services..........................	78,572							78,572
1. 8	Station Service.............................	1,723	29	1,163	93	53	377	8	
1. 9	Corp/Bureau.................................	3,750		3,526	224				
1.10	Remedial Action Scheme (RAS)................	231					231		
1.11	Gen'l Transfer Agrmnts for nonfederal pwr.......	4,365		4,365					
1.12	Leases...	5,267		5,188	79				
1.13	Depreciation.....................................	182,694	2,447	120,424	2,688	2,433	26,717	4,127	23,858
1.14	Interest Credit from Facilities Sales...........	-752	0	0	-376	-376	0	0	0
1.15	Interest...	183,637	2,966	132,609	3,312	2,909	24,810	4,764	12,267
1.16	Net Revenues for Risk...........................	10,751	174	7,763	194	170	1,453	279	718
1.17	Total Cost.......................................	698,677	8,015	424,288	10,664	7,710	78,753	11,197	158,050

Table 1
Transmission Revenue Requirements
($000)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		TBL	Generation		Delivery		Intertie		Ancillary
		Total	Integration	Network	Utility	Industry	Southern	Eastern	Services
	FY 2003								
1.18	Gross Plant....................................	4,878,682	60,378	3,647,491	69,323	61,221	688,185	27,059	325,025
1.19	Lines......................................	2,220,237	16,557	1,989,686	4,249	1,968	205,808	1,968	
1.20	Stations...................................	2,333,420	43,821	1,657,805	65,074	59,253	482,377	25,091	
1.21	Net Plant......................................	3,147,250	48,108	2,313,749	55,059	48,557	398,558	76,568	206,651
1.22	Operating Expenses.............................	222,563	2,340	145,468	4,337	2,456	24,529	1,966	41,467
1.23	Generation Inputs..............................								
1.24	Ancillary Services.........................	78,572							78,572
1.25	Station Service............................	1,723	29	1,163	93	53	377	8	
1.26	Corp/Bureau................................	3,717		3,491	226				
1.27	Remedial Action Scheme (RAS)................	231					231		
1.28	Gen'l Transfer Agrmnts for nonfederal pwr.......	4,365		4,365					
1.29	Leases...	5,267		5,188	79				
1.30	Depreciation...................................	195,358	2,527	129,490	2,819	2,560	27,478	4,239	26,245
1.31	Interest Credit from Facilities Sales...........	-750	0	0	-375	-375	0	0	0
1.32	Interest.......................................	179,620	2,746	132,050	3,142	2,771	22,747	4,370	11,794
1.33	Net Revenues for Risk..........................	9,829	150	7,226	172	152	1,245	239	645
1.34	Total Cost.....................................	700,495	7,792	428,441	10,493	7,617	76,607	10,822	158,723
	Average FY 2002 and FY 2003								
1.35	Total Cost.....................................	699,586	7,904	426,364	10,579	7,664	77,680	11,010	158,387

Table 2
Revenue Credits

		(A) FY 2002 ($000)	(B) FY 2003 ($000)	(C) AVERAGE ($000)
	Transmission Revenue Credit			
2. 1	AC Rate..............................	1,375	1,375	1,375
2. 2	CSPE Whlg............................	268	127	198
2. 3	Fiber................................	15,000	19,800	17,400
2. 4	Fiber Depreciation...................	696	696	696
2. 5	Irrigation Pumping Power.............	1,288	1,288	1,288
2. 6	NFP Depreciation.....................	3,335	3,335	3,335
2. 7	Operations and Maintenance...........	675	675	675
2. 8	PC Wireless..........................	4,070	4,430	4,250
2. 9	Power Factor Penalty Charge..........	5,000	5,000	5,000
2.10	Remedial Action Scheme (RAS).........	597	597	597
2.11	Supplemental Capacity Whlg...........	62	27	45
2.12	TGT..................................	10,136	10,136	10,136
2.13	Use of Facilities (UFT)..............	5,679	5,679	5,679
2.14	Total..............................	48,181	53,165	50,673

Credit Segmentation Factors (decimals)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Generation		Delivery		Intertie		Ancillary
		Total	Integration	Network	Utility	Industrial	Southern	Eastern	Services
2.15	AC Rate..............................	1.00000	-	-	-	-	1.0000	-	-
2.16	CSPE Whlg............................	1.00000	0.0364	0.9497	0.0138	-	-	-	-
2.17	Fiber................................	1.00000	0.0114	0.5307	0.0129	0.0114	0.0953	0.0183	0.3200
2.18	Fiber Depreciation...................	1.00000	0.0114	0.5307	0.0129	0.0114	0.0953	0.0183	0.3200
2.19	Irrigation Pumping Power.............	1.00000	-	1.0000	-	-	-	-	-
2.20	NFP Depreciation.....................	1.00000	-	-	-	-	1.0000	-	-
2.21	Operations and Maintenance...........	1.00000	0.0159	0.9674	0.0116	0.0000	0.0051	-	-
2.22	PC Wireless..........................	1.00000	-	1.0000	-	-	-	-	-
2.23	Power Factor Penalty Charge..........	1.00000	-	1.0000	-	-	-	-	-
2.24	Remedial Action Scheme (RAS).........	1.00000	-	-	-	-	1.0000	-	-
2.25	Supplemental Capacity Whlg...........	1.00000	0.0370	0.9630	-	-	-	-	-
2.26	TGT..................................	1.00000	-	0.0282	-	-	-	0.9718	-
2.27	Use of Facilities (UFT)..............	1.00000	0.0012	0.7145	0.0497	-	0.1560	0.0786	-

Table 2
Revenue Credits
($000)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Generation		Delivery		Intertie		Ancillary
	Integration	Network	Utility	Industrial	Southern	Eastern	Services
FY 2002 Revenue							
2.28 AC Rate................................	-	-	-	-	1,375	-	-
2.29 CSPE Whlg..............................	10	255	4	-	-	-	-
2.30 Fiber..................................	172	7,960	194	171	1,429	274	4,800
2.31 Fiber Depreciation......................	8	369	9	8	66	13	223
2.32 Irrigation Pumping Power................	-	1,288	-	-	-	-	-
2.33 NFP Depreciation........................	-	-	-	-	3,335	-	-
2.34 Operations and Maintenance..............	11	653	8	0	3	-	-
2.35 PC Wireless.............................	-	4,070	-	-	-	-	-
2.36 Power Factor Penalty Charge.............	-	5,000	-	-	-	-	-
2.37 Remedial Action Scheme (RAS)............	-	-	-	-	597	-	-
2.38 Supplemental Capacity Whlg..............	2	60	-	-	-	-	-
2.39 TGT.....................................	-	285	-	-	-	9,850	-
2.40 Use of Facilities (UFT).................	7	4,057	282	-	886	446	-
2.41 **Subtotal FY 2002......................**	**209**	**23,997**	**497**	**179**	**7,692**	**10,584**	**5,023**
FY 2003 Revenue							
2.42 AC Rate................................	-	-	-	-	1,375	-	-
2.43 CSPE Whlg..............................	5	121	2	-	-	-	-
2.44 Fiber..................................	227	10,507	256	225	1,886	362	6,336
2.45 Fiber Depreciation......................	8	369	9	8	66	13	223
2.46 Irrigation Pumping Power................	-	1,288	-	-	-	-	-
2.47 NFP Depreciation........................	-	-	-	-	3,335	-	-
2.48 Operations and Maintenance..............	11	653	8	0	3	-	-
2.49 PC Wireless.............................	-	4,430	-	-	-	-	-
2.50 Power Factor Penalty Charge.............	-	5,000	-	-	-	-	-
2.51 Remedial Action Scheme (RAS)............	-	-	-	-	597	-	-
2.52 Supplemental Capacity Whlg..............	1	26	-	-	-	-	-
2.53 TGT.....................................	-	285	-	-	-	9,850	-
2.54 Use of Facilities (UFT).................	7	4,057	282	-	886	446	-
2.55 **Subtotal FY 2003......................**	**258**	**26,737**	**557**	**233**	**8,150**	**10,672**	**6,559**

Table 2
Revenue Credits
($000)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Generation		Delivery		Intertie		Ancillary
	Integration	Network	Utility	Industrial	Southern	Eastern	Services
Two Year Average, FY 2002 and FY 2003							
2.56 AC Rate................................	-	-	-	-	1,375	-	-
2.57 CSPE Whlg..............................	7	188	3	-	-	-	-
2.58 Fiber..................................	199	9,234	225	198	1,658	318	5,568
2.59 Fiber Depreciation......................	8	369	9	8	66	13	223
2.60 Irrigation Pumping Power................	-	1,288	-	-	-	-	-
2.61 NFP Depreciation........................	-	-	-	-	3,335	-	-
2.62 Operations and Maintenance..............	11	653	8	0	3	-	-
2.63 PC Wireless.............................	-	4,250	-	-	-	-	-
2.64 Power Factor Penalty Charge.............	-	5,000	-	-	-	-	-
2.65 Remedial Action Scheme (RAS)............	-	-	-	-	597	-	-
2.66 Supplemental Capacity Whlg..............	2	43	-	-	-	-	-
2.67 TGT.....................................	-	285	-	-	-	9,850	-
2.68 Use of Facilities (UFT).................	7	4,057	282	-	886	446	-
2.69 **Average of FY 2002 and FY 2003........**	**233**	**25,367**	**527**	**206**	**7,921**	**10,628**	**5,791**

Table 3
Rate Development Costs
($000/Yr)

		(A)	(B)	(C)	(D)	(F)	(G)	(H)
		Generation Integration	Network	Delivery Utility	Delivery Industry	Intertie Southern	Intertie Eastern	Ancillary Services
	FY 2002							
3. 1	Unadjusted Costs (Table 1)	8,015	424,288	10,664	7,710	78,753	11,197	158,050
3. 2	Revenue Credits (Table 2)	-209	-23,997	-497	-179	-7,692	-10,584	-5,023
3. 3	DSI Stability Reserves 1/	0	0	0	0	496	0	0
3. 4	Eastern Intertie Adjustment 2/	10	455	11	10	85	-613	42
3. 5	Total	7,816	400,745	10,179	7,541	71,642	0	153,069
	FY 2003							
3. 6	Unadjusted Costs (Table 1)	7,792	428,441	10,493	7,617	76,607	10,822	158,723
3. 7	Revenue Credits (Table 2)	-258	-26,737	-557	-233	-8,150	-10,672	-6,559
3. 8	DSI Stability Reserves 1/	0	0	0	0	496	0	0
3. 9	Eastern Intertie Adjustment 2/	2	113	3	2	20	-150	10
3.10	Total	7,537	401,817	9,939	7,386	68,973	0	152,174
	Average FY 2002 and FY 2003							
3.11	Unadjusted Costs	7,904	426,364	10,579	7,664	77,680	11,010	158,387
3.12	Revenue Credits	-233	-25,367	-527	-206	-7,921	-10,628	-5,791
3.13	DSI Stability Reserves	0	0	0	0	496	0	0
3.14	Eastern Intertie Adjustment	6	284	7	6	52	-382	26
3.15	Total	7,676	401,281	10,059	7,464	70,307	0	152,622

1/ Stability reserves credit based on DSI smelter load of 2613 MW times credit of $0.01582/kW-mo.

2/ Eastern Intertie adjustment (cost - revenue) segmented on Table 1 net plant percentages.

Table 4
Long-Term Transmission Loads
(Megawatts)

	Transmission Rate Schedule	Units 1/	(A) Oct	(B) Nov	(C) Dec	(D) Jan	(F) Feb	(G) Mar	(H) Apr	(I) May	(J) Jun	(K) Jul	(L) Aug	(M) Sep	(N) Annual	(O) Winter Oct-Mar (MW-mo)	(P) Summer Apr-Aug (MW-mo)
	Network																
	FY 2002																
4. 1	Formula Power Transmission (FPT).......	a_cd	3,532	3,532	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,532	**3,508**		
4. 2	Integration of Resources (IR)...........	a_cd	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	**3,991**		
4. 3	Point to Point (PTP)....................	a_cd	7,353	7,353	7,633	7,629	7,629	7,629	8,029	8,029	8,029	8,029	7,629	7,629	**7,717**		
4. 4	Point to Point (PTP) /2.................	m_cd	1,645	1,557	1,557	1,557	1,557	1,557	1,579	1,682	1,710	1,549	1,387	1,387	**1,560**		
4. 5	Network Contract Demand (NCD)...........	a_cd	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	**4,591**		
4. 6	Network Integration (NT, Base Charge)...	cp	3,873	3,990	4,769	4,844	**4,920**	3,938	3,474	3,248	2,930	3,116	3,239	3,026	**3,781**		
4. 7	Subtotal Network		24,985	25,014	26,040	26,111	26,187	25,205	25,163	25,040	24,750	24,775	24,336	24,156	**25,147**		
	FY 2003																
4. 8	Formula Power Transmission (FPT).......	a_cd	3,532	3,532	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,532	**3,508**		
4. 9	Integration of Resources (IR)...........	a_cd	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	3,991	**3,991**		
4.10	Point to Point (PTP)....................	a_cd	7,629	7,629	7,629	7,429	7,429	7,429	7,829	7,829	7,829	7,719	7,319	7,319	**7,585**		
4.11	Point to Point (PTP) /2.................	m_cd	1,519	1,431	1,431	1,431	1,431	1,431	1,981	2,084	2,112	1,973	1,957	1,957	**1,728**		
4.12	Network Contract Demand (NCD)...........	a_cd	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	4,591	**4,591**		
4.13	Network Integration (NT, Base Charge)...	cp	4,163	4,314	5,160	5,234	**5,349**	4,278	3,760	3,363	3,110	3,289	3,409	3,141	**4,047**		
4.14	Subtotal Network......................		25,425	25,488	26,301	26,175	26,289	25,219	25,651	25,357	25,132	25,062	24,766	24,531	**25,450**		
4.15	Network Integration (Load Shaping) FY02	cp	4,131	4,231	5,007	5,077	5,153	4,178	3,721	3,503	3,191	3,358	3,484	3,276	**4,026**		
4.16	Network Integration (Load Shaping) FY03	cp	4,637	4,769	5,616	5,696	5,811	4,739	4,213	3,818	3,574	3,738	3,865	3,600	**4,506**		
	Southern Intertie																
	FY 2002																
4.17	Intertie South (IS), North to South.....	m_cd	129	129	96	96	96	96	96	96	96	96	96	129	**104**	642	609
4.18	Intertie South (IS), South to North.....	m_cd	271	271	271	271	271	271	271	271	271	271	271	271	**271**	0	0
4.19	Point to Point (PTP)....................	a_cd	2,686	2,686	2,686	2,686	2,686	2,686	3,081	3,081	3,081	3,081	3,081	2,681	**2,850**	16,116	18,086
4.20	Point to Point (PTP) /2.................	m_cd	405	317	317	317	317	317	317	420	448	462	462	462	**380**	1,990	2,571
4.21	Subtotal Intertie.....................		3,491	3,403	3,370	3,370	3,370	3,370	3,765	3,868	3,896	3,910	3,910	3,543	**3,606**	18,748	21,266
	FY 2003																
4.22	Intertie South (IS), North to South.....	m_cd	129	129	96	96	96	96	96	96	96	96	96	129	**104**	642	609
4.23	Intertie South (IS), South to North.....	m_cd	271	271	271	271	271	271	271	271	271	271	271	271	**271**	0	0
4.24	Point to Point (PTP)....................	a_cd	2,681	2,681	2,681	2,481	2,481	2,481	2,481	2,481	2,481	2,426	2,426	2,426	**2,517**	15,486	14,721
4.25	Point to Point (PTP) /2.................	m_cd	419	331	331	331	331	331	331	434	462	498	498	498	**400**	2,074	2,721
4.26	Subtotal Intertie.....................		3,500	3,412	3,379	3,179	3,179	3,179	3,179	3,282	3,310	3,291	3,291	3,324	**3,292**	18,202	18,051

1/ Annual (a_cd) or monthly (m_cd) contract demand; "cp" coincidenttal peak denotes contribution to TBL transmission system peak load.
2/ Monthly demands from PBL grandfathered agreements.

Table 5
Short-Term Transmission Loads
(Megawatts)

	Short-term Product	Source	Units	(A) Oct.	(B) Nov.	(C) Dec.	(D) Jan.	(F) Feb.	(G) Mar.	(H) Apr.	(I) May	(J) Jun.	(K) Jul.	(L) Aug.	(M) Sep.	(N) Annual	North to South (O) Oct-Mar (MW-mos)	North to South (P) Apr-Sep (MW-mos)
			(MW)															
	Network																	
	FY 1998																	
5. 1	Monthly........................	Oasis Reservations	MW-mos.	922	1,163	2,892	958	1,648	2,473	2,077	3,184	3,375	2,946	3,088	2,532	**2,271**		
5. 2	Weekly.........................	Oasis Reservations	MW-mos.	1,500	482	276	1,243	501	134	137	243	516	759	68	224	**507**		
5. 3	Daily..........................	Oasis Reservations	MW-mos.	298	100	69	129	139	82	26	37	206	234	4	90	**118**		
5. 4	Hourly.........................	1/	aMW	1,234	590	206	120	494	266	272	313	616	747	526	314	**475**		
	Daily equivalent of Monthly, Weekly, and Daily																	
5. 5	Daily Block1 Product..........	1st 5 Days of Reservations	MW-mos.	431	594	500	552	498	382	581	856	891	508	635	0	**536**		
5. 6	Daily Block2 Product..........	Reservations beyond 5th day	MW-mos.	1,688	1,314	2,642	1,830	1,736	2,190	1,858	2,883	3,241	3,048	2,652	2,211	**2,275**		
	FY 1999																	
5. 7	Monthly........................	Oasis Reservations	MW-mos.	782	493	973	1,753	2,855	2,390	3,563	2,822	2,798	3,932	3,367	2,208	**2,328**		
5. 8	Weekly.........................	Oasis Reservations	MW-mos.	39	5	41	147	39	877	20	30	31	70	25	0	**110**		
5. 9	Daily..........................	Oasis Reservations	MW-mos.	32	9	10	114	4	28	14	6	25	42	28	19	**28**		
5.10	Hourly.........................	FY 1999 Transmission Bills	aMW	11	151	431	1,893	1,013	1,294	365	234	487	327	351	348	**575**		
	Daily equivalent of Monthly, Weekly, and Daily																	
5.11	Daily Block1 Product..........	1st 5 Days of Reservations	MW-mos.	106	62	170	477	495	657	602	437	451	692	517	366	**419**		
5.12	Daily Block2 Product..........	Reservations beyond 5th day	MW-mos.	747	444	853	1,536	2,402	2,638	2,994	2,421	2,403	3,353	2,902	1,859	**2,046**		
	Southern Intertie																	
	FY 1998																	
5.13	Monthly........................	Oasis Reservations	MW-mos.	0	50	370	645	750	750	1,485	1,550	1,853	1,824	2,864	2,490	**1,219**		
5.14	Weekly.........................	Oasis Reservations	MW-mos.	341	229	104	0	13	33	0	11	0	30	4	0	**64**		
5.15	Daily..........................	Oasis Reservations	MW-mos.	49	33	13	0	4	58	33	12	0	167	0	1	**31**		
5.16	Hourly.........................	1/	aMW	1,180	908	495	330	531	312	300	159	378	788	786	550	**560**	3,755	2,960
	Daily equivalent of Monthly, Weekly, and Daily																	
5.17	Daily Block1 Product..........	1st 5 Days of Reservations	MW-mos.	209	110	103	77	58	81	260	48	84	225	203	269	**144**	638	1,089
5.18	Daily Block2 Product..........	Reservations beyond 5th day	MW-mos.	181	202	384	568	709	759	1,258	1,525	1,768	1,796	2,665	2,222	**1,170**	2,803	11,234
5.19	**Forecast Overrun Due to Increases in Long-term Contracts 2/**		MW-mos.	-375	-268	-282	-150	-150	-150	-449	-315	-338	-945	-1,163	-113	**-392**	-1,375	-3,324
	FY 1999																	
5.20	Monthly........................	Oasis Reservations	MW-mos.	332	220	10	77	200	1,009	1,110	1,141	1,110	1,284	1,284	660	**703**		
5.21	Weekly.........................	Oasis Reservations	MW-mos.	0	0	0	68	0	30	186	0	0	0	0	116	**33**		
5.22	Daily..........................	Oasis Reservations	MW-mos.	0	18	12	55	0	2	59	29	126	473	283	118	**98**		
5.23	Hourly.........................	FY 1999 Transmission Bills	aMW	52	144	122	573	167	81	94	79	124	419	129	131	**176**	1,139	976
	Daily equivalent of Monthly, Weekly, and Daily																	
5.24	Daily Block1 Product..........	1st 5 Days of Reservations	MW-mos.	0	56	12	135	0	178	100	34	126	440	280	256	**135**	381	1,236
5.25	Daily Block2 Product..........	Reservations beyond 5th day	MW-mos.	332	182	10	65	200	865	1,256	1,137	1,110	1,110	1,110	598	**664**	1,653	6,321
5.26	**Forecast Overrun Due to Increases in Long-term Contracts 2/**		MW-mos.	-379	-272	-286	-65	-65	-65	-190	-56	-10	-53	-271	-16	**-144**	-1,134	-596

1/ Use in excess of long-term plus short-term reservations.

2/ Lines 5.19 and 5.26 are increases in long term contracts times -44% for FY1998 and FY1999, respectively.

Table 6
FPT Rate: Network Unit Cost Increase

		(A)	(B)	(C)	(D)	(E)
		/------- 1996 Current Rates ---------/		/---------------- Proposed Rates -----------------/		Change in Network
		Source	Amount (varies)	Source	Amount (varies)	Unit Cost (%)
	Ancillary Service Cost ($000/yr)					
6. 1	Scheduling Control & Dispatch........................			Table 11.1(A+C)	67,782	
6. 2	Generation Supplied Reactive.........................			Table 11.2(A+C)	30,912	
	Network Power Flows; Network Sales (MW-yr)					
6. 3	Total Transmission System Loading....................	Pwr Flow Case J9710, 1996	29,394	Pwr Flow Case J02CY99, 1999	29,564	
6. 4	Total Network Base Rate Development Megawatts.........			7.14 - 7.10 + (4.6N+4.13N)/2 + 6.12(D)	29,230	
6. 5	Total Southern Intertie Rate Development Megawatts			Table 8.14(C)	5,066	
	Rate Development Costs ($000/yr)					
6. 6	Network Rate Development Costs.......................	96TRDS 3.37(B)/5	350,620	Table 3.15(B)	401,281	
6. 7	Network-related Scheduling Control & Dispatch.........			6.1 * 6.4/(6.4+6.5)	57,770	
6. 8	Network-related Generation Supplied Reactive..........			6.2 * 6.4/(6.4+6.5)	26,346	
6. 9	Subtotal Generally Applicable Network Cost..........			6.6 + 6.7 + 6.8	485,397	
6.10	Network Unit Cost ($/kW-mo)..........................	6.6(B)/(6.3B*12)	0.994	6.9(D)/(6.3D*12)	1.368	
6.11	**Percent Increase in Unit Costs, 2002 Case over 1996 Case**	6.10(D)/6.10(B)				**37.64%**
	FPT Revenues ($000/yr)					
6.12	FPT Sales (MW), FY 2002 and FY 2003.................	Table 4.1 and 4.8	3,508	Table 4.1 and 4.8	3,508	
6.13	FPT Revenues ($000), FY 2002 and FY 2003.............	FPT-96 * 6.12(B)	31,084	(1+ 6.11(E)) * 6.13(B)	**42,785**	
6.14	Unit FPT Revenue ($/kW-mo)...........................	6.13(B) / (6.12(B)*12)	0.738	6.13(D) / (6.12(D)*12)	1.016	
	Attribution of Unit Cost Increase and FPT Revenue ($000/yr)					
6.15	Network Rate Development Costs.......................			6.13 * 6.6(D) / 6.9(D)	35,371	**82.67%**
6.16	Network-related Scheduling Control & Dispatch.........			6.13 * 6.7(D) / 6.9(D)	5,092	**11.90%**
6.17	Network-related Generation Supplied Reactive..........			6.13 * 6.8(D) / 6.9(D)	2,322	**5.43%**
					42,785	**100.00%**

Table 7
Calculation of Network Rates: IR, PTP, NCD, NT

		(A) Units	(B) Source	(C) Sales (MW-Years)	(D) Sales (MW-Periods)	(E) Costs ($000)	(F) Rates (Unit Costs)
	Network Costs						
7. 1	Rate Development Costs................	($000/Yr)	Table 3.15(B)			401,281	
7. 2	Revenues from FPT.....................	($000/Yr)	Table 6.15(D)			-35,371	
7. 3	Base Charge Rate Development Costs.....	($000/Yr)	7.1(E) - 7.2(E)			365,910	
	Network Sales (PTP, IR, NCD, NT_1cp)						
7. 4	Long-term Agreements..................	(MW-yr)	Table 4(N) Avg Annual IR, PTP, NCD	17,877			
7. 5	NT 1cp................................	(cp_MW)	(Table 4.6(F) + 4.13(F)) / 2	5,134			
7. 6	Short-term Daily, Block1..............	(MW-yr)	(Table 5.5(N) + 5.11(N)) / 2	477			
7. 7	Short-term Daily, Block2..............	(MW-yr)	(Table 5.6(N) + 5.12(N)) / 2	2,160			
7. 8	Short-term Hourly.....................	(aMW)	(Table 5.4(N) + 5.10(N)) / 2	525			
	Rate Design Megawatts						
7. 9	Long-term Agreements..................	(MW-yr)	7.4	17,877			
7.10	NT 1cp	(cp_MW)	7.5	5,134			
7.11	Short-term Daily, Block1..............	(MW-yr)	7.6 * 7/5	668			
7.12	Short-term Daily, Block2..............	(MW-yr)	7.7	2,160			
7.13	Short-term Hourly.....................	(aMW)	7.8 * 7/5 * 24/16	1,103			
7.14	Total: Base Rate Divisor..............	(MW)	7.9 + 7.10 + 7.11 + 7.12 + 7.13	**26,942**			
	Network Base Charge						
7.15	Annual................................	(kW-yr)	7.3(E) / 7.14(C)				13.58
7.16	Monthly...............................	($/kW-mo)	annual / 12				**1.132**
7.17	Daily Block1 (day 1 through 5).........	($/kW-day)	annual / (365*5/7)				**0.052**
7.18	Daily Block2 (day 6 and beyond)........	($/kW-day)	annual / 365				**0.037**
7.19	Hourly................................	(mills/kWh)	annual/[(8.760/168) * 5 * 16]				**3.26**
	Base Charge Revenues						
7.20	Point-to-Point (PTP)..................	(a_cd)	(Table 4(N) lines 3+4+10+11)/2 *12*7.16		111,544	126,268	
7.21	Integration of Resources (IR).........	(a_cd)	(Table 4.2(N)+4.9(N))/2 * 12 * 7.16		47,887	54,208	
7.22	Network Contract Demand (NCD)..........	(a_cd)	(Table 4.5(N)+4.12(N))/2 * 12 * 7.16		55,088	62,360	
7.23	Network Transmission (NT).............	(12cp_MW)	(Table 4.6(N)+4.13(N))/2 * 12 * 7.16		46,968	53,167	
7.24	Short-term Network Daily Block1........	(d_cd)	7.6 * 365 * 7.17		174,265	9,062	
7.25	Short-term Network Daily Block2........	(d_cd)	7.7 * 365 * 7.18		788,513	29,175	
7.26	Short-term Network Hourly.............	(GWh)	7.8 * 8.76 * 7.19		4,601	14,999	
7.27	Subtotal Base Charge..................	($000)				349,239	

Table 7
Calculation of Network Rates: IR, PTP, NCD, NT

		(A) Units	(B) Source	(C) Sales (MW-Years)	(D) Sales (MW-Periods)	(E) Costs ($000)	(F) Rates (Unit Costs)
	Load Shaping Revenue Requirement						
7.28	Base Charge Rate Development Costs.....	($000)	7.3(E)			365,910	
7.29	Base Charge Revenues...................	($000)	7.27(E)			349,239	
7.30	Load Shaping Costs.....................	($000)	7.28(E) - 7.29(E)			16,671	
7.31	Load Shaping Sales.....................	(cp_MW-yr)	(Table 4.15(N) + 4.16(N)) / 2	4,266			
7.32	Load Shaping Charge....................	($/kW-yr)	7.30(E) / 7.31(C)				3.91
7.33	Load Shaping Charge....................	($/kW-mo)	7.32 / 12				**0.326**
7.34	**Total Charge: Base plus Load Shaping**	($/kW-mo)	7.16 + 7.33				**1.458**

Table 8
Southern Intertie Rate Calculation

		(A)	(B)	(C)	(D)	(E)
					North to South	
		Units	Source	Annual	Oct-Mar	Apr-Sep
					(MW-mos)	(MW-mos)
	Intertie Costs					
8. 1	Rate Development Costs............	($000/Yr)	Table 3.15(F)	70,307		
	Southern Intertie Sales					
8. 2	Long-term Agreements, N-S..........	(MW-Yr)	(Table 4(N) lines 21+26-18-23)/2	3,178	18,475	19,659
8. 3	Long-term Agreements, S-N..........	(MW-Yr)	(Table 4.18(N) + 4.23(N)) / 2	271	0	0
8. 4	Overstatement of Short-Term........	(MW-Yr)	(Table 5.19(N) + 5.26(N)) / 2	-268	-1,254	-1,960
8. 5	Short-term Daily Block1............	(MW-Yr)	(Table 5.17(N) + 5.24(N)) / 2	139	510	1,162
8. 6	Short-term Daily Block2............	(MW-Yr)	(Table 5.18(N) + 5.25(N)) / 2	917	2,228	8,778
8. 7	Short-term Hourly..................	(aMW)	(Table 5.16(N) + 5.23(N)) / 2	368	2,447	1,968
	Southern Intertie Rate Design Megawattts					
8. 8	Long-term Agreements, N-S..........	(MW-Yr)	8.2	3,178	18,475	19,659
8. 9	Long-term Agreements, S-N..........	(MW-Yr)	8.3	271	0	0
8.10	Overstatement of Short-Term........	(MW-Yr)	8.4	-268	-1,254	-1,960
8.11	Short-term Daily Block1............	(MW-Yr)	8.5 * 7/5	195	713	1,627
8.12	Short-term Daily Block2............	(MW-Yr)	8.6	917	2,228	8,778
8.13	Short-term Hourly..................	(aMW)	8.7 * 7/5 * 24/16	773	5,139	4,132
8.14	Total............................	(MW)		5,066	25,301	32,236
	South to North, Year Around IS Rate					
8.15	Annual............................	($/kW-yr)	8.1 / 8.14	13.88		
8.16	Monthly...........................	($/kW-mo)	annual / 12	**1.157**		
8.17	Daily Block1 (day 1 through 5).....	($/kW-day)	annual / (365*5/7)	**0.053**		
8.18	Daily Block2 (day 6 and beyond)	($/kW-day)	annual / 365	**0.038**		
8.19	Hourly............................	(mills/kWh)	annual /[(8.760/168) * 5 * 16]	**3.33**		
	South to North Revenue					
8.20	Monthly...........................	($000)	8.3(C)*12 * 8.16	3,763		
	Summer Season, N-S, Rate Design Megwatts					
8.21	75% of Winter, Oct - Mar..........	(MW-mos)	8.14(D) * .75	18,976		
8.22	Summer, Apr - Sep.................	(MW-mos)	8.14(E)	32,236		
8.23	Total............................	(MW-mos)	8.21 + 8.22	51,212		
	North to South, Summer Season Unit Cost, expressed annually					
8.24	Annual............................	($/kW-yr)	8.25 * 12	15.59		
	North to South, Summer (Apr-Sep) Season IS Rate					
8.25	Monthly, April through September	($/kW-mo)	(8.1(C)-8.20(C)) / 8.23	**1.299**		
8.26	Daily Block1 (day 1 through 5).....	($/kW-day)	annual / (365*5/7)	**0.060**		
8.27	Daily Block2 (day 6 and beyond)	($/kW-day)	annual / 365	**0.043**		
8.28	Hourly............................	(mills/kWh)	annual /[(8.760/168) * 5 * 16]	**3.74**		
	North to South, Winter (Oct-Mar) Season IS Rate					
8.29	Monthly, October through March.....	($/kW-mo)	Summer Monthly * .75	**0.974**		
8.30	Daily Block1 (day 1 through 5).....	($/kW-day)	Summer Daily Block1 * .75	**0.045**		
8.31	Daily Block2 (day 6 and beyond)	($/kW-day)	Summer Daily Block2 * .75	**0.032**		
8.32	Hourly............................	(mills/kWh)	Summer Hourly * .75	**2.81**		

Table 9
Montana Intertie and Eastern Intertie Rate Calculations

		(A)	(B)	(C)
		Source	Units	Amount
	Montana Intertie (IM) Rate Calculation			
9. 1	TBL's Payments in the Calculation of TGT 1/........	81BP-90210 Exhibit D, Rev. D, 1998	($000/yr)	2,751
9. 2	TBL Montana Intertie Share.........................	same	(MW-yr)	185
9. 3	IM-02 Annual Unit Cost.............................	9.1 / 9.2	($/kW-yr)	14.87
9. 4	IM-02 Monthly Demand Charge........................	annual / 12	($/kW-mo)	**1.239**
9. 5	IM-02 Daily Block1 Demand Charge...................	annual / (365*5/7)	($/kW-day)	**0.057**
9. 6	IM-02 Daily Block2 Demand Charge...................	annual / 365	($/kW-day)	**0.041**
9. 7	IM-02 Hourly Rate..................................	annual /[(8.760/168) * 5 * 16]	(mills/kWh)	**3.56**
	Eastern Intertie (IE) Rate Calculation 2/			
9. 8	Eastern Intertie Costs.............................	Table 1, Col(G)	($000/yr)	11,010
9. 9	TGT Rate Billing Determinant.......................	81BP-90210 Exhibit D, Rev. D, 1998	(MW-yr)	1,915
9.10	Nominal Eastern Intertie Unit Cost.................	9.8 / 9.9	($/kW-yr)	5.75
9.11	Eastern Intertie Rate..............................	9.10 /[(8.760/168) * 5 * 16]	(mills/kWh)	**1.38**

1/ The Montana Intertie runs from Garrison to Broadview.

2/ The Eastern Intertie is the western (Townsend to Garrison) portion of the Montana Intertie. IE rate is used to credit the TGT rate on an anticipated basis. It also may be used by the six particpants in association with non-Colstrip power.

Table 10
Delivery Rate Calculations:
Utility and DSI

		(A) Units	(B) Source	(C) Amount
	Utility Delivery Charge			
10. 1	Rate Development Costs..............	($000/Yr)	Table 3(C)	10,059
10. 2	Billing Determinant.................	(cp_MW-yr)	Appendix C	645
10. 3	Utility Delivery Charge.............	($/kW-yr)	10.1(C) / 10.2(C)	15.59
10. 4	Utility Delivery Charge.............	($/kW-mo)	10.3(C) / 12	**1.299**
	Industry Delivery Charge			
10. 5	Segment Costs.......................	($000)	Table 3.15(F)	7,464
10. 6	UFT Revenues........................	($000)	Appendix G.3(E)	6,237
10. 7	Adjustment Factor...................	(decimal)	10.5 / 10.6	**1.197**

Table 11
Ancillary Service Rates

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					FPT			/---------------- R A T E S ----------------/				
		Avg RRQ	**Revenue Credits 1/**		**Credits 5/**	**Adj RRQ**	**Sales**	**Annual**	**Monthly**	**Daily 1**	**Daily 2**	**Hourly**
		($000)	Alloc. %	($000)	($000)	($000)	(MW-Yr)	($/kW-yr)	($/kW-mo)	($/kW-day)	($/kW-day)	(mills/kWh)
	Ancillary Service Costs											
11. 1	Scheduling Control & Dispatch 2/.....	72,105	75%	-4,323	-5,092	62,690	30,788	2.04	**0.170**	**0.008**	**0.005**	**0.49**
11. 2	Generation Supplied Reactive 2/......	31,092	3%	-180	-2,322	28,590	29,663	0.96	**0.080**	**0.004**	**0.003**	**0.23**
11. 3	Regulation & Frequency Response......	17,129	22%	-1,261		15,868	6,109					**0.30**
11. 4	Energy Imbalance.....................	0	0%	0		0	none					**100.00**
11. 5	Operating Reserves - Spinning 3/.....	19,037	0%	0		19,037	263					**8.27**
11. 6	Operating Reserves - Supplemental 3/	19,024	0%	0		19,024	263					**8.27**
11. 7	Total Ancillary....................	158,387	100%	-5,765	-7,414	145,208						

			Source
	Transmission Sales (Rate Design MW)		
11. 8	Network (excluding FPT)..............	25,722	6.4 - 6.12
11. 9	Southern Intertie....................	5,066	8.14(C)
11.10	Total Sales..........................	30,788	11.8 + 11.9
11.11	Less Gen Reactive Self Supply 4/.....	-1,125	
11.12	Net Sales............................	29,663	11.10 + 11.11
	Reserve Obligations		
11.13	PBL 5% Reserve Obligation (hydro)....	464	WPRDS WP-02-E-BPA-05 4.1.2.3
11.14	PBL 7% Reserve Obligation (thermal)	61	WPRDS WP-02-E-BPA-05 4.1.2.4
11.15	PBL Total Reserve Obligation.........	525	WPRDS WP-02-E-BPA-05 4.1.2.5
11.16	PBL Spinning Reserve Obligation......	263	11.15 / 2
11.17	PBL Supplemental Reserve Obligation	263	11.15 / 2
	Control Area Load		
11.18	Control Area Load (Avg 98/99)........	5,700	
11.19	CA Load w/ Load Growth...............	6,109	

1/ Revenue Credits and Eastern Intertie Adjustment from Table 3. Allocation based on distribution of fiber investment from Segmentation Study (TR-02-E-BPA-02), Documentation Chapter 8.

2/ For Scheduling/Disp. and Generation Supplied Reactive, Daily 1 (day 1-5) is annual/(365*5/7), Daily 2 (day 6 and beyond) is annual/(365). Hourly is annual/((8.760/168)*5*16).

3/ Rate will be applied to the reserve obligation of load served by generation in the BPA control area.

4/ Estimated 4500MW of nonfederal generation which is directly connected to the FCRTS, and is west of the Cascades or near the head of the Southern Intertie. Of this, assumed 50% would be eligible to self supply generation reactive. Of those eligible, assumed a 50% reduction in billing demand.

5/ Table 6.16(D) and 6.17(D).

Table 12
Revenues from FPT
($000)

	Resource	Contract	Rate	(A) Demand	(B) Compensation Factors Current 96	(C) Compensation Factors Proposed	(D) Revenues Current 96	(E) Revenues Proposed	(F) %Change (E)/(D)
				(MW)	($/kW-yr)	($/kW-yr)	($000/yr)	($000/yr)	(%)
	Avista (WWP)								
12.01	WNP-3	92186	FPT.1	32.2	16.920	23.277	545	750	38%
12.02	Avista System (GTA)	91970	FPT.1	65.3	8.310	11.481	542	749	38%
12.03				97.5			1,088	1,499	38%
	Cowlitz Co PUD								
12.04	Priest Rapids	13520	FPT.3	17.0	10.300	14.255	175	242	38%
12.05	Swift	92043	FPT.1	77.0	3.990	5.491	307	423	38%
12.06	Wanapum	00025	FPT.1	21.0	10.650	14.654	224	308	38%
12.07				115.0			706	973	38%
	Douglas Co PUD								
12.08	Nilles Corner	90066	FPT.1	1.8	4.940	6.793	9	12	38%
12.09	Wells	92389	FPT.1	4.5	5.540	7.630	25	34	38%
12.10				6.3			34	47	38%
	Okanogan Co PUD								
12.11	Wells	90013	FPT.1	-	0.000	0.000	-	-	N.A.
	PacifiCorp								
12.12	Centralia	09228	FPT.3	638.0	6.050	8.327	3,860	5,313	38%
12.13	Clatsop	14612	FPT.3	7.0	14.050	19.343	98	135	38%
12.14	Colstrip	90168	FPT.1	140.0	18.400	25.316	2,576	3,544	38%
12.15	Hermiston	94316	FPT.1	490.0	12.220	16.819	5,988	8,241	38%
12.16	Midpoint-Medford	94333	FPT.1	600.0	13.910	19.134	8,346	11,481	38%
12.17	Priest Rapids	90100	FPT.1	235.0	2.850	3.927	670	923	38%
12.18	PSW(DC)/PPL	94280	FPT.1	200.0	4.070	5.598	814	1,120	38%
12.19	Swift	92269	FPT.1	222.0	4.340	5.971	963	1,326	38%
12.20	Wanapum	26811	FPT.1	269.0	10.400	14.314	2,798	3,851	38%
12.21	Widco	92325	FPT.1	17.3	7.350	10.119	127	175	38%
12.22				2,818.3			26,240	36,107	38%
	Pend Orille Co PUD								
12.23	Boundary POI	92488	FPT.1	32.0	5.510	7.584	176	243	38%
12.24	Box Canyon	90006	FPT.1	-	0.000	0.000	-	-	N.A.
12.25				32.0			176	243	38%
	Portland General Electric								
12.26	Boardman Unit 1	92260	FPT.1	75.0	4.990	6.873	374	515	38%
12.27	WNP-3	92187	FPT.1	53.7	8.820	12.148	474	652	38%
12.28				128.7			848	1,168	38%
	Power Resources Coop (PNGC)								
12.29	Boardman	94151	FPT.1	50.0	4.570	6.293	229	315	38%
	Puget Sound Power and Light								
12.30	WNP-3	92185	FPT.1	32.2	7.320	10.085	236	325	38%
	Tacoma Public Utilities								
12.31	Priest Rapids	13512	FPT.3	71.1	8.530	11.824	606	841	39%
12.32	Centralia	94304	FPT.1	107.0	4.550	6.270	487	671	38%
12.33	NFP	93936	FPT.1	49.3	8.830	12.157	435	599	38%
12.34				227.4			1,528	2,110	38%
12.35	**TOTAL**			**3,507.4**			**31,084**	**42,787**	**38%**

Table 13
Summary of Rate Level Changes

		Units	(A) Current 1996 Rates	(C) Proposed 2002 Rates	(D) Percent Change (C)/(A) (percent)
	FPT-02.1 and FPT-02.3				
13. 1	M-G Distance...........................	($/kW-mi-yr)	0.0405	0.0557	37.5%
13. 2	M-G Miscellaneous Facilities...........	($/kW-yr)	2.31	3.18	37.7%
13. 3	M-G Terminal...........................	($/kW-yr)	0.47	0.65	38.3%
13. 4	M-G Interconnection Terminal...........	($/kW-yr)	0.42	0.58	38.1%
13. 5	S-S Transformation.....................	($/kW-yr)	4.35	5.99	37.7%
13. 6	S-S Interconnection Terminal...........	($/kW-yr)	1.19	1.64	37.8%
13. 7	S-S Intermediate Terminal..............	($/kW-yr)	1.68	2.31	37.5%
13. 8	S-S Distance...........................	($/kW-mi-yr)	0.3980	0.5478	37.6%
13. 9	Overall FPT Rate.....................	($/kW-yr)	8.86	12.19	37.6%
13.10	Overall FPT Rate.....................	($/kW-mo)	0.738	1.0160	37.6%
	IR-02/NCD-02				
13.11	Demand.................................	($/kW-mo)	1.000	1.132	13.2%
	NT-02				
13.12	Base Rate ($/kW-mo)....................	($/kW-mo)	1.000	1.132	13.2%
13.13	Load Shaping ($/kW-mo).................	($/kW-mo)	0.539	0.326	-39.5%
13.14	Base plus Load Shaping...............	($/kW-mo)	1.539	1.458	-5.3%
	PTP-02				
13.15	Demand.................................	($/kW-mo)	1.000	1.132	13.2%
13.16	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.046	0.052	13.0%
13.17	Daily Block 2 (day 6 and beyond).......	($/kW-day)	0.033 1/	0.037	12.1%
13.18	Hourly.................................	(mills/kWh)	2.52	3.26	29.4%
	PTP and NT Unauthorized Increase Charge				
13.19	Demand.................................	($/kW-mo)	12.00	6.79	-43.4%
	Utility Delivery				
13.20	Demand.................................	($/kW-mo)	0.750	1.299	73.2%
	IS-02				
	North to South				
	Winter (Oct-Mar)				
13.21	Demand............................	($/kW-mo)	1.274	0.974	-23.5%
13.22	Daily Block 1 (day 1 thru 5).......	($/kW-day)	0.059	0.045	-23.5%
13.23	Daily Block 2 (day 6 and beyond)...	($/kW-day)	0.042 1/	0.032	-23.8%
13.24	Hourly............................	(mills/kWh)	2.54	2.81	10.6%
	Summer (Apr-Sep)				
13.25	Demand............................	($/kW-mo)	1.274	1.299	2.0%
13.26	Daily Block 1 (day 1 thru 5).......	($/kW-day)	0.059	0.060	2.0%
13.27	Daily Block 2 (day 6 and beyond)...	($/kW-day)	0.042 1/	0.043	2.4%
13.28	Hourly............................	(mills/kWh)	2.54	3.74	47.2%
	South to North, Year Around				
13.29	Demand..............................	($/kW-mo)	1.274	1.157	-9.2%
13.30	Daily Block 1 (day 1 thru 5).........	($/kW-day)	0.059	0.053	-9.9%
13.31	Daily Block 2 (day 6 and beyond).....	($/kW-day)	0.042 1/	0.038	-9.5%
13.32	Hourly..............................	(mills/kWh)	2.54	3.33	31.1%

Table 13
Summary of Rate Level Changes

		Units	(A) Current 1996 Rates	(C) Proposed 2002 Rates	(D) Percent Change (C)/(A) (percent)
	IM-02				
13.33	Demand................................	($/kW-mo)	1.234	1.239	0.4%
13.34	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	0.057	0.057	0.0%
13.35	Daily Block 2 (day 6 and beyond).......	($/kW-day)	0.041 1/	0.041	0.0%
13.36	Hourly................................	(mills/kWh)	3.56	3.56	0.0%
	Intertie East				
13.37	IE-02.................................	(mills/kWh)	1.68	1.38	-17.9%
	Power Factor Penalty Charge				
13.38	Demand -- Lagging......................	($/kVAr-mo)	0.08	0.28	250.0%
13.39	Demand -- Leading......................	($/kVAr-mo)	0.06	0.24	300.0%
13.40	Energy -- Lagging or Leading...........	($/kVAr-hour)	0.53	n.a.	
	Scheduling Control and Dispatch				
13.41	Demand................................	($/kW-mo)	n.a.	0.170	
13.42	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	n.a.	0.008	
13.43	Daily Block 2 (day 6 and beyond).......	($/kW-day)	n.a.	0.005	
13.44	Hourly................................	(mills/kWh)	n.a.	0.49	
	Generation Supplied Reactive				
13.45	Demand................................	($/kW-mo)	n.a.	0.080	
13.46	Daily Block 1 (day 1 thru 5)...........	($/kW-day)	n.a.	0.004	
13.47	Daily Block 2 (day 6 and beyond).......	($/kW-day)	n.a.	0.003	
13.48	Hourly................................	(mills/kWh)	n.a.	0.23	
	Regulation and Frequency Response				
13.49	Hourly................................	(mills/kWh)	n.a.	0.30	
	Energy Imbalance				
13.50	Hourly................................	(mills/kWh)	n.a.	100.00	
	Operating Reserves				
13.51	Spinning..............................	(mills/kWh)	n.a.	8.27	
13.52	Supplemental..........................	(mills/kWh)	n.a.	8.27	

1/ 1996 weekly rate divided by seven.

Table 14

Transmission Revenue Summary

($000)

	Service	Rate	(A) FY 2002	(B) FY 2003	(C) 2-Yr Total
	General Transmission				
14. 1	Formula Power Transmission..................	FPT-02	42,787	42,787	85,573
14. 2	Integration of Resources....................	IR-02	54,208	54,208	108,417
14. 3	Network Transmission, Base..................	NT-02	51,354	54,980	106,335
14. 4	Network Transmission, Load Shaping..........	NT-02	15,749	17,629	33,378
14. 5	Network Contract Demand.....................	NCD-02	62,359	62,359	124,717
14. 6	Point to Point, Long-term Contracts.........	PTP-02	126,024	126,513	252,537
14. 7	Point to Point, Daily Block 1..............	PTP-02	9,066	9,066	18,132
14. 8	Point to Point, Daily Block 2..............	PTP-02	29,203	29,203	58,406
14. 9	Point to Point, Hourly......................	PTP-02	14,987	14,987	29,973
14.10	**Subtotal General Rates, Network**		**405,737**	**411,731**	**817,468**
14.11	Southern Intertie, Long-term Contracts......	IS-02	49,648	44,940	94,587
14.12	Southern Intertie, Daily Block 1...........	IS-02	2,443	2,443	4,885
14.13	Southern Intertie, Daily Block 2...........	IS-02	11,893	11,893	23,786
14.14	Southern Intertie, Hourly..................	IS-02	8,829	8,829	17,658
14.15	**Subtotal General Rates, Southern Intertie**		**72,812**	**68,104**	**140,916**
14.16	Montana Intertie...........................	IM-02	0	0	0
14.17	Intertie East..............................	IE-02	0	0	0
14.18	DSI Delivery Charge........................	UFT-02	7,368	7,559	14,927
14.19	Utility Delivery Charge....................	UD	9,981	10,129	20,110
14.20	**Subtotal General Transmission Rates**		**495,898**	**497,524**	**993,421**
	Other				
14.21	Annual Cost Rate...........................		1,375	1,375	2,751
14.22	Columbia Storage Power Exchange............		268	127	395
14.23	Fiber......................................		15,000	19,800	34,800
14.24	Fiber Depreciation.........................		696	696	1,392
14.25	Generation Integration.....................		7,816	7,537	15,353
14.26	Irrigation Pumping Power...................		1,288	1,288	2,577
14.27	Nonfederal Participation Depreciation.......		3,335	3,335	6,670
14.28	Operations and Maintenance.................		675	675	1,350
14.29	Personal Communications Wireless...........		4,070	4,430	8,500
14.30	Power Factor Penalty Charge................		5,000	5,000	10,000
14.31	Remedial Action Scheme.....................		597	597	1,194
14.32	Supplemental Capacity Wheeling.............		62	27	89
14.33	Townsend Garrison Transmission.............		10,136	10,136	20,271
14.34	Use of Facilities..........................		5,679	5,679	11,358
14.35	**Subtotal Other Transmission**		**55,997**	**60,702**	**116,699**
	Ancillary				
14.36	Scheduling Control & Dispatch..............		62,215	62,193	124,408
14.37	Generation Supplied Reactive...............		28,753	28,758	57,511
14.38	Regulation & Frequency Response............		16,036	16,036	32,072
14.39	Energy Imbalance...........................		0	0	0
14.40	Operating Reserves - Spinning..............		18,994	18,994	37,988
14.41	Operating Reserves - Supplemental		18,994	18,994	37,988
14.42	**Subtotal Ancillary Services**		**144,991**	**144,975**	**289,967**
14.43	**Total Revenue**		**696,886**	**703,201**	**1,400,087**
14.44	**Total TBL Table 1 Costs**		**698,677**	**700,495**	**1,399,172**
14.45	**Revenue Longfall (Shortfall)**		**(1,791)**	**2,706**	**915**

APPENDICES

APPENDIX A

Long-Term Transmission Demands

Appendix A
Long-term Transmission Demands
(Megawatts)

FY 2002

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1	AVISTA CORP. (WWP)...........	FPT.1	MS79-85BP92186	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
2	AVISTA CORP. (WWP)...........	FPT.1	DE-MS79-86BP91970	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
3	COWLITZ COUNTY PUD NO 1......	FPT.1	MS79-86BP92043	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.1
4	COWLITZ COUNTY PUD NO 1......	FPT.1	EW78-Y-83-00025	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
5	DOUGLAS COUNTY PUD NO 1......	FPT.1	MS79-88BP92389	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
6	DOUGLAS COUNTY PUD NO 1......	FPT.1	MS79-80BP90066	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8
7	PACIFIC POWER & LIGHT COM....	FPT.1	14-03-26811	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0
8	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-79BP90100	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	234.9
9	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-81BP90168	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
10	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-86BP92269	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.1
11	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-87BP92325	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
12	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.1
13	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94316	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0
14	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94333	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
15	PEND OREILLE COUNTY PUD N....	FPT.1	MS79-90BP92488	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
16	PORTLAND GENERAL ELECTRIC....	FPT.1	MS79-85BP92187	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
17	PORTLAND GENERAL ELECTRIC....	FPT.1	MS79-86BP92260	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	74.9
18	POWER RESOURCES COOPERATI....	FPT.1	MS79-95BP94151	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.1
19	PUGET ENERGY SERVICE, INC....	FPT.1	MS79-85BP92185	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
20	TACOMA, CITY OF.............	FPT.1	MS79-94BP93936	74.0	74.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	74.0	49.3
21	TACOMA, CITY OF.............	FPT.1	96-MS-94304	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	106.9
22	COWLITZ COUNTY PUD NO 1......	FPT.3	14-03-001-13520	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
23	PACIFIC POWER & LIGHT COM....	FPT.3	14-03-09228	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.1
24	PACIFIC POWER & LIGHT COM....	FPT.3	14-03-14612	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
25	TACOMA, CITY OF.............	FPT.3	14-03-13512	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
26	TOTAL FPT....................			3,532.4	3,532.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,532.4	3,507.8
27	EUGENE WATER & ELECTRIC B....	IR	MS79-86BP91651	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
28	EUGENE WATER & ELECTRIC B....	IR	MS79-86BP91651	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8
29	FOREST GROVE, CITY OF........	IR	MS79-86BP91652	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
30	KITTITAS COUNTY PUD NO 1.....	IR	MS79-86BP91845	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
31	KITTITAS COUNTY PUD NO 1.....	IR	MS79-86BP91845	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
32	MILTON-FREEWATER, CITY OF....	IR	MS79-86BP91655	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
33	PORTLAND GENERAL ELECTRIC....	IR	MS79-89BP92273	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0
34	PORTLAND GENERAL ELECTRIC....	IR	MS79-89BP92273	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0
35	PUGET ENERGY SERVICE, INC....	IR	MS79-94BP93947	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0
36	PUGET ENERGY SERVICE, INC....	IR	14-03-001-13439	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
37	PUGET ENERGY SERVICE, INC....	IR	14-03-001-13574	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
38	PUGET ENERGY SERVICE, INC....	IR	14-03-001-14502	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39	PUGET ENERGY SERVICE, INC....	IR	14-03-39361	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
40	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92427	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
41	PUGET ENERGY SERVICE, INC....	IR	14-03-45241	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0
42	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92461	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
43	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92781	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
44	VANALCO, INC.................	IR	MS79-95BP94768	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6
45	TOTAL IR.....................			3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6

Appendix A
Long-term Transmission Demands
(Megawatts)

FY 2002

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
46	BENTON RURAL ELECTRIC ASS....	NCD	Modeled NCD	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6
47	CENTRAL MONTANA ELECTRIC.....	NCD	Modeled NCD	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6
48	COWLITZ COUNTY PUD NO 1......	NCD	Modeled NCD	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0
49	EUGENE WATER & ELECTRIC B....	NCD	Modeled NCD	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.7
50	FLATHEAD ELECTRIC COOPERA....	NCD	Modeled NCD	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
51	FRANKLIN COUNTY PUD NO 1.....	NCD	Modeled NCD	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3
52	IDAHO FALLS, CITY OF.........	NCD	Modeled NCD	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
53	MASON COUNTY PUD 3...........	NCD	Modeled NCD	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1
54	SEATTLE, CITY OF.............	NCD	Modeled NCD	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0
55	SNOHOMISH COUNTY PUD NO 1....	NCD	Modeled NCD	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0
56	TACOMA, CITY OF..............	NCD	Modeled NCD	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0
57	TOTAL NCD....................			4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.7
58	ALCOA/NORTHWEST ALLOYS,IN....	PTP	00TX-NW_ALLOYS	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
59	AVISTA CORP. (WWP)...........	PTP	96MS-96008	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0
60	AVISTA CORP. (WWP)...........	PTP	97TX-50002	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0
61	B.C. POWER EXPORT CORPORA....	PTP	97TX-96084	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
62	BONNEVILLE POWER BUSINESS....	PTP	96MS-95363	1,635.0	1,635.0	1,635.0	1,631.0	1,631.0	1,631.0	1,631.0	1,631.0	1,631.0	1,631.0	1,631.0	1,631.0	1,632.0
63	BONNEVILLE POWER BUSINESS....	PTP	96MS-96060	1,645.0	1,557.0	1,557.0	1,557.0	1,557.0	1,557.0	1,579.0	1,682.0	1,710.0	1,549.0	1,387.0	1,387.0	1,560.3
64	COLUMBIA FALLS ALUMINUM C....	PTP	98TX-10139	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0
65	CONSOLIDATED ENERGY SERVI....	PTP	00TX-CONSOLID_LADWP	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
66	DOUGLAS COUNTY PUD NO 1......	PTP	00TX-xxPBL	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
67	ELF ATOCHEM NORTH AMERICA....	PTP	01TX-ELFATOCHEM@RC	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
68	ENGAGE ENERGY US, L.P........	PTP	98TX-10158	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
69	ENRON POWER MARKETING........	PTP	00TX-COYOTE SPRNG #2	0.0	0.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	233.3
70	GOLDENDALE (COLUMBIA ALUM....	PTP	96MS-96109	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0
71	GRANT COUNTY PUD NO 2........	PTP	00TX-xxPRWAN	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
72	HERMISTON POWER PARTNERSH....	PTP	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
73	IDAHO POWER COMPANY..........	PTP	96MS-96108	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
74	IDAHO POWER COMPANY..........	PTP	96MS-96108	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4
75	INTALCO ALUMINUM CORPORAT....	PTP	00TX-INTALCO	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0
76	KAISER ALUMINUM COMPANY......	PTP	97TX-96107	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
77	KAISER ALUMINUM COMPANY......	PTP	97TX-96107DS	48.0	48.0	48.0	48.0	48.0	48.0	448.0	448.0	448.0	448.0	48.0	48.0	181.3
78	KLICKITAT COUNTY PUD NO 1....	PTP	97TX-10038	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1
79	NORTHWEST ALUMINUM COMPAN....	PTP	96MS-96111	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
80	PACIFIC POWER & LIGHT COM....	PTP	96MS-96035	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
81	PACIFIC POWER & LIGHT COM....	PTP	96MS-96035	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8
82	PACIFIC POWER & LIGHT COM....	PTP	99TX-PPLCS	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
83	PENNSYLVANIA GLOBAL..........	PTP	98TX-10210	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0
84	PENNSYLVANIA GLOBAL..........	PTP	98TX-10211	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
85	PORTLAND GENERAL ELECTRIC....	PTP	96MS-96095	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
86	PORTLAND GENERAL ELECTRIC....	PTP	96MS-96097x	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
87	REYNOLDS METALS COMPANY......	PTP	01TX-REYNOLDS@RC	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0
88	TACOMA, CITY OF..............	PTP	98TX-10103	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
89	TOTAL PTP....................			8,998.4	8,910.4	9,190.4	9,186.4	9,186.4	9,186.4	9,608.4	9,711.4	9,739.4	9,578.4	9,016.4	9,016.4	9,277.3

Appendix A
Long-term Transmission Demands
(Megawatts)

FY 2002

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
90	BONNEVILLE POWER BUSINESS....	IS	96MS-95363	1,760.0	1,760.0	1,760.0	1,760.0	1,760.0	1,760.0	2,155.0	2,155.0	2,155.0	2,155.0	2,155.0	1,755.0	1,924.2
91	BONNEVILLE POWER BUSINESS....	IS	96MS-96060	405.0	317.0	317.0	317.0	317.0	317.0	317.0	420.0	448.0	462.0	462.0	462.0	380.1
92	CONSOLIDATED ENERGY SERVI....	IS	00TX-CONSOLID_LADWP	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
93	HERMISTON POWER PARTNERSH....	IS	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
94	IDAHO POWER COMPANY..........	IS	91BP-93094	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
95	KLAMATH FALLS, CITY OF.......	IS	99TX-KFALLS_GENPROJ	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
96	PACIFIC POWER & LIGHT COM....	IS	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
97	PACIFIC POWER & LIGHT COM....	IS	MS79-94BP94285	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
98	TACOMA, CITY OF.............	IS	MS79-94BP92490	33.0	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.0	8.2
99	TOTAL IS....................			3,491.0	3,403.0	3,370.0	3,370.0	3,370.0	3,370.0	3,765.0	3,868.0	3,896.0	3,910.0	3,910.0	3,543.0	3,605.5

Appendix A
Long-term Transmission Demands
(Megawatts)

FY 2003

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
100	AVISTA CORP. (WWP)...........	FPT.1	MS79-85BP92186	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
101	AVISTA CORP. (WWP)...........	FPT.1	DE-MS79-86BP91970	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
102	COWLITZ COUNTY PUD NO 1......	FPT.1	MS79-86BP92043	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.1
103	COWLITZ COUNTY PUD NO 1......	FPT.1	EW78-Y-83-00025	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
104	DOUGLAS COUNTY PUD NO 1......	FPT.1	MS79-88BP92389	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
105	DOUGLAS COUNTY PUD NO 1......	FPT.1	MS79-80BP90066	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8
106	PACIFIC POWER & LIGHT COM....	FPT.1	14-03-26811	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0
107	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-79BP90100	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	235.0	234.9
108	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-81BP90168	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
109	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-86BP92269	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.0	222.1
110	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-87BP92325	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
111	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.1
112	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94316	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0
113	PACIFIC POWER & LIGHT COM....	FPT.1	MS79-94BP94333	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
114	PEND OREILLE COUNTY PUD N....	FPT.1	MS79-90BP92488	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
115	PORTLAND GENERAL ELECTRIC....	FPT.1	MS79-85BP92187	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
116	PORTLAND GENERAL ELECTRIC....	FPT.1	MS79-86BP92260	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	74.9
117	POWER RESOURCES COOPERATI....	FPT.1	MS79-95BP94151	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.1
118	PUGET ENERGY SERVICE, INC....	FPT.1	MS79-85BP92185	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2	32.2
119	TACOMA, CITY OF..............	FPT.1	MS79-94BP93936	74.0	74.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	74.0	49.3
120	TACOMA, CITY OF..............	FPT.1	96-MS-94304	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	106.9
121	COWLITZ COUNTY PUD NO 1......	FPT.3	14-03-001-13520	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
122	PACIFIC POWER & LIGHT COM....	FPT.3	14-03-09228	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.0	638.1
123	PACIFIC POWER & LIGHT COM....	FPT.3	14-03-14612	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
124	TACOMA, CITY OF..............	FPT.3	14-03-13512	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
125	TOTAL FPT....................			3,532.4	3,532.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,499.4	3,532.4	3,507.8
126	EUGENE WATER & ELECTRIC B....	IR	MS79-86BP91651	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
127	EUGENE WATER & ELECTRIC B....	IR	MS79-86BP91651	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8	-15.8
128	FOREST GROVE, CITY OF........	IR	MS79-86BP91652	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
129	KITTITAS COUNTY PUD NO 1.....	IR	MS79-86BP91845	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
130	KITTITAS COUNTY PUD NO 1.....	IR	MS79-86BP91845	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
131	MILTON-FREEWATER, CITY OF....	IR	MS79-86BP91655	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
132	PORTLAND GENERAL ELECTRIC....	IR	MS79-89BP92273	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0	1,973.0
133	PORTLAND GENERAL ELECTRIC....	IR	MS79-89BP92273	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0	-36.0
134	PUGET ENERGY SERVICE, INC....	IR	MS79-94BP93947	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0	494.0
135	PUGET ENERGY SERVICE, INC....	IR	14-03-001-13439	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
136	PUGET ENERGY SERVICE, INC....	IR	14-03-001-13574	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
137	PUGET ENERGY SERVICE, INC....	IR	14-03-001-14502	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
138	PUGET ENERGY SERVICE, INC....	IR	14-03-39361	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
139	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92427	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
140	PUGET ENERGY SERVICE, INC....	IR	14-03-45241	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0
141	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92461	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
142	PUGET ENERGY SERVICE, INC....	IR	MS79-92BP92781	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
143	VANALCO, INC.................	IR	MS79-95BP94768	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6	229.6
144	TOTAL IR.....................			3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6	3,990.6

Appendix A

Long-term Transmission Demands

(Megawatts)

FY 2003

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
145	BENTON RURAL ELECTRIC ASS....	NCD	Modeled NCD	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6	103.6
146	CENTRAL MONTANA ELECTRIC.....	NCD	Modeled NCD	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6	113.6
147	COWLITZ COUNTY PUD NO 1......	NCD	Modeled NCD	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0	403.0
148	EUGENE WATER & ELECTRIC B....	NCD	Modeled NCD	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.6	399.7
149	FLATHEAD ELECTRIC COOPERA....	NCD	Modeled NCD	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1	78.1
150	FRANKLIN COUNTY PUD NO 1.....	NCD	Modeled NCD	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3
151	IDAHO FALLS, CITY OF.........	NCD	Modeled NCD	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
152	MASON COUNTY PUD 3...........	NCD	Modeled NCD	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1	152.1
153	SEATTLE, CITY OF............	NCD	Modeled NCD	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0	1,312.0
154	SNOHOMISH COUNTY PUD NO 1....	NCD	Modeled NCD	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0	1,689.0
155	TACOMA, CITY OF.............	NCD	Modeled NCD	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0
156	TOTAL NCD...................			4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.6	4,590.7
157	ALCOA/NORTHWEST ALLOYS,IN....	PTP	00TX-NW_ALLOYS	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
158	AVISTA CORP. (WWP)..........	PTP	96MS-96008	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0
159	AVISTA CORP. (WWP)..........	PTP	97TX-50002	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0	265.0
160	B.C. POWER EXPORT CORPORA....	PTP	97TX-96084	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0	230.0
161	BONNEVILLE POWER BUSINESS....	PTP	96MS-95363	1,631.0	1,631.0	1,631.0	1,431.0	1,431.0	1,431.0	1,431.0	1,431.0	1,431.0	1,321.0	1,321.0	1,321.0	1,453.5
162	BONNEVILLE POWER BUSINESS....	PTP	96MS-96060	1,519.0	1,431.0	1,431.0	1,431.0	1,431.0	1,431.0	1,981.0	2,084.0	2,112.0	1,973.0	1,957.0	1,957.0	1,728.2
163	COLUMBIA FALLS ALUMINUM C....	PTP	98TX-10139	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0	254.0
164	CONSOLIDATED ENERGY SERVI....	PTP	00TX-CONSOLID_LADWP	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
165	DOUGLAS COUNTY PUD NO 1......	PTP	00TX-xxPBL	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
166	ELF ATOCHEM NORTH AMERICA....	PTP	01TX-ELFATOCHEM@RC	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
167	ENGAGE ENERGY US, L.P........	PTP	98TX-10158	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
168	ENRON POWER MARKETING........	PTP	00TX-COYOTE SPRNG #2	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
169	GOLDENDALE (COLUMBIA ALUM....	PTP	96MS-96109	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0	305.0
170	GRANT COUNTY PUD NO 2........	PTP	00TX-xxPRWAN	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0	135.0
171	HERMISTON POWER PARTNERSH....	PTP	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
172	IDAHO POWER COMPANY..........	PTP	96MS-96108	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0	61.0
173	IDAHO POWER COMPANY..........	PTP	96MS-96108	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4	-7.4
174	INTALCO ALUMINUM CORPORAT....	PTP	00TX-INTALCO	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0
175	KAISER ALUMINUM COMPANY......	PTP	97TX-96107	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
176	KAISER ALUMINUM COMPANY......	PTP	97TX-96107DS	48.0	48.0	48.0	48.0	48.0	48.0	448.0	448.0	448.0	448.0	48.0	48.0	181.3
177	KLICKITAT COUNTY PUD NO 1....	PTP	97TX-10038	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1	67.1
178	NORTHWEST ALUMINUM COMPAN....	PTP	96MS-96111	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
179	PACIFIC POWER & LIGHT COM....	PTP	96MS-96035	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
180	PACIFIC POWER & LIGHT COM....	PTP	96MS-96035	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8
181	PACIFIC POWER & LIGHT COM....	PTP	99TX-PPLCS	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
182	PENNSYLVANIA GLOBAL..........	PTP	98TX-10210	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0	633.0
183	PENNSYLVANIA GLOBAL..........	PTP	98TX-10211	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
184	PORTLAND GENERAL ELECTRIC....	PTP	96MS-96095	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
185	PORTLAND GENERAL ELECTRIC....	PTP	96MS-96097x	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
186	REYNOLDS METALS COMPANY......	PTP	01TX-REYNOLDS@RC	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0	688.0
187	TACOMA, CITY OF.............	PTP	98TX-10103	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
188	TOTAL PTP...................			9,148.4	9,060.4	9,060.4	8,860.4	8,860.4	8,860.4	9,810.4	9,913.4	9,941.4	9,692.4	9,276.4	9,276.4	9,313.4

Appendix A
Long-term Transmission Demands
(Megawatts)

FY 2003

	CUSTOMER	RATE	CONTRACT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
189	BONNEVILLE POWER BUSINESS....	IS	96MS-95363	1,755.0	1,755.0	1,755.0	1,555.0	1,555.0	1,555.0	1,555.0	1,555.0	1,555.0	1,500.0	1,500.0	1,500.0	1,591.2
190	BONNEVILLE POWER BUSINESS....	IS	96MS-96060	419.0	331.0	331.0	331.0	331.0	331.0	331.0	434.0	462.0	498.0	498.0	498.0	399.6
191	CONSOLIDATED ENERGY SERVI....	IS	00TX-CONSOLID_LADWP	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
192	HERMISTON POWER PARTNERSH....	IS	98TX-10154	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0	536.0
193	IDAHO POWER COMPANY..........	IS	91BP-93094	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
194	KLAMATH FALLS, CITY OF.......	IS	99TX-KFALLS_GENPROJ	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
195	PACIFIC POWER & LIGHT COM....	IS	MS79-94BP94280	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
196	PACIFIC POWER & LIGHT COM....	IS	MS79-94BP94285	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
197	TACOMA, CITY OF..............	IS	MS79-94BP92490	33.0	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.0	8.2
	TOTAL IS.....................			3,500.0	3,412.0	3,379.0	3,179.0	3,179.0	3,179.0	3,179.0	3,282.0	3,310.0	3,291.0	3,291.0	3,324.0	3,292.0

APPENDIX B

NT Base and Load Shaping Sales

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1	ALBION, CITY OF	102		Base	TBL load forecast	2002	0.51	0.61	0.70	0.77	0.78	0.62	0.49	0.39	0.28	0.32	0.26	0.29	0.50
2	ALBION, CITY OF	102		LS	TBL load forecast	2002	0.51	0.61	0.70	0.77	0.78	0.62	0.49	0.39	0.28	0.32	0.26	0.29	0.50
3	ALBION, CITY OF	102		Base	TBL load forecast	2003	0.51	0.62	0.71	0.78	0.79	0.62	0.49	0.40	0.28	0.32	0.27	0.29	0.51
4	ALBION, CITY OF	102		LS	TBL load forecast	2003	0.51	0.62	0.71	0.78	0.79	0.62	0.49	0.40	0.28	0.32	0.27	0.29	0.51
5	ALDER MUTUAL LIGHT COMPANY	301		Base	TBL load forecast	2002	0.64	0.71	0.83	0.76	0.81	0.68	0.54	0.40	0.30	0.28	0.29	0.30	0.55
6	ALDER MUTUAL LIGHT COMPANY	301		LS	TBL load forecast	2002	0.64	0.71	0.83	0.76	0.81	0.68	0.54	0.40	0.30	0.28	0.29	0.30	0.55
7	ALDER MUTUAL LIGHT COMPANY	301		Base	TBL load forecast	2003	0.65	0.72	0.85	0.77	0.83	0.69	0.55	0.41	0.30	0.29	0.30	0.30	0.55
8	ALDER MUTUAL LIGHT COMPANY	301		LS	TBL load forecast	2003	0.65	0.72	0.85	0.77	0.83	0.69	0.55	0.41	0.30	0.29	0.30	0.30	0.55
9	ASHLAND, CITY OF	103		Base	TBL load forecast	2002	21.79	24.09	27.61	32.57	31.86	28.82	25.76	21.75	20.72	25.07	27.45	22.17	25.81
10	ASHLAND, CITY OF	103		LS	TBL load forecast	2002	25.79	28.09	31.61	32.57	31.86	28.82	25.76	21.75	20.72	25.07	27.45	22.17	26.81
11	ASHLAND, CITY OF	103		Base	TBL load forecast	2003	25.82	28.12	31.65	32.62	31.90	28.86	25.79	21.78	20.74	25.10	27.49	22.20	26.84
12	ASHLAND, CITY OF	103		LS	TBL load forecast	2003	25.82	28.12	31.65	32.62	31.90	28.86	25.79	21.78	20.74	25.10	27.49	22.20	26.84
13	ASOTIN COUNTY PUD	201		Base	recent pwr bills	2002	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.10	0.41	0.72	1.36	1.41	0.35
14	ASOTIN COUNTY PUD	201		LS	recent pwr bills	2002	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.10	0.41	0.72	1.36	1.41	0.35
15	ASOTIN COUNTY PUD	201		Base	recent pwr bills	2003	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.10	0.41	0.72	1.36	1.41	0.35
16	ASOTIN COUNTY PUD	201		LS	recent pwr bills	2003	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.10	0.41	0.72	1.36	1.41	0.35
17	BANDON, CITY OF	104		Base	TBL load forecast	2002	9.87	10.49	11.38	12.42	13.49	12.31	11.18	8.43	6.51	6.74	6.26	6.56	9.64
18	BANDON, CITY OF	104		LS	TBL load forecast	2002	9.87	10.49	11.38	12.42	13.49	12.31	11.18	8.43	6.51	6.74	6.26	6.56	9.64
19	BANDON, CITY OF	104		Base	TBL load forecast	2003	10.07	10.70	11.61	12.67	13.76	12.55	11.41	8.60	6.64	6.87	6.38	6.69	9.83
20	BANDON, CITY OF	104		LS	TBL load forecast	2003	10.07	10.70	11.61	12.67	13.76	12.55	11.41	8.60	6.64	6.87	6.38	6.69	9.83
21	BIG BEND ELECTRIC COOP	306		Base	TBL load forecast	2002	51.81	33.61	37.43	40.23	38.32	30.41	51.38	77.76	106.47	93.70	99.18	81.60	61.83
22	BIG BEND ELECTRIC COOP	306		LS	TBL load forecast	2002	51.81	33.61	37.43	40.23	38.32	30.41	51.38	77.76	106.47	93.70	99.18	81.60	61.83
23	BIG BEND ELECTRIC COOP	306		Base	TBL load forecast	2003	52.36	33.97	37.82	40.65	38.73	30.73	51.92	78.57	107.59	94.69	100.22	82.46	62.48
24	BIG BEND ELECTRIC COOP	306		LS	TBL load forecast	2003	52.36	33.97	37.82	40.65	38.73	30.73	51.92	78.57	107.59	94.69	100.22	82.46	62.48
25	BLACHLY-LANE COUNTY COOP	309	PNGC	Base	TBL load forecast	2002	27.37	24.99	30.99	30.33	33.92	27.62	26.41	22.19	19.30	19.79	18.80	18.69	25.03
26	BLACHLY-LANE COUNTY COOP	309	PNGC	LS	TBL load forecast	2002	27.37	24.99	30.99	30.33	33.92	27.62	26.41	22.19	19.30	19.79	18.80	18.69	25.03
27	BLACHLY-LANE COUNTY COOP	309	PNGC	Base	TBL load forecast	2003	27.88	25.46	31.56	30.89	34.55	28.14	26.90	22.61	19.66	20.16	19.15	19.04	25.50
28	BLACHLY-LANE COUNTY COOP	309	PNGC	LS	TBL load forecast	2003	27.88	25.46	31.56	30.89	34.55	28.14	26.90	22.61	19.66	20.16	19.15	19.04	25.50
29	BLAINE, CITY OF	106		Base	TBL load forecast	2002	9.52	9.93	11.14	10.61	10.66	8.02	7.04	6.29	5.43	5.89	5.73	7.04	8.11
30	BLAINE, CITY OF	106		LS	TBL load forecast	2002	9.52	9.93	11.14	10.61	10.66	8.02	7.04	6.29	5.43	5.89	5.73	7.04	8.11
31	BLAINE, CITY OF	106		Base	TBL load forecast	2003	9.57	9.98	11.19	10.66	10.71	8.06	7.08	6.32	5.46	5.92	5.76	7.08	8.15
32	BLAINE, CITY OF	106		LS	TBL load forecast	2003	9.57	9.98	11.19	10.66	10.71	8.06	7.08	6.32	5.46	5.92	5.76	7.08	8.15
33	BUREAU OF INDIAN AFFAIRS	482		Base	TBL load forecast	2002	0.95	0.03	0.04	0.05	0.06	0.04	0.79	2.62	3.18	2.54	2.49	3.31	1.34
34	BUREAU OF INDIAN AFFAIRS	482		LS	TBL load forecast	2002	0.95	0.03	0.04	0.05	0.06	0.04	0.79	2.62	3.18	2.54	2.49	3.31	1.34
35	BUREAU OF INDIAN AFFAIRS	482		Base	TBL load forecast	2003	0.96	0.03	0.04	0.05	0.06	0.04	0.79	2.63	3.20	2.55	2.51	3.33	1.35
36	BUREAU OF INDIAN AFFAIRS	482		LS	TBL load forecast	2003	0.96	0.03	0.04	0.05	0.06	0.04	0.79	2.63	3.20	2.55	2.51	3.33	1.35
37	BURLEY, CITY OF	109		Base	TBL load forecast	2002	15.78	18.54	22.83	22.28	21.80	18.06	15.72	14.70	15.69	16.97	17.91	15.84	18.01
38	BURLEY, CITY OF	109		LS	TBL load forecast	2002	15.78	18.54	22.83	22.28	21.80	18.06	15.72	14.70	15.69	16.97	17.91	15.84	18.01
39	BURLEY, CITY OF	109		Base	TBL load forecast	2003	15.92	18.70	23.04	22.47	21.99	18.22	15.86	14.83	15.83	17.12	18.07	15.98	18.17
40	BURLEY, CITY OF	109		LS	TBL load forecast	2003	15.92	18.70	23.04	22.47	21.99	18.22	15.86	14.83	15.83	17.12	18.07	15.98	18.17
41	CANBY, CITY OF, UTILITY BD	111		Base	T_PGE except 1MW	2002	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
42	CANBY, CITY OF, UTILITY BD	111		LS	T_PGE except 1MW	2002	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
43	CANBY, CITY OF, UTILITY BD	111		Base	T_PGE except 1MW	2003	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
44	CANBY, CITY OF, UTILITY BD	111		LS	T_PGE except 1MW	2003	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Appendix B

NT Base and Load Shaping Sales
FY 2002 and FY 2003
(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
45	CASCADE LOCKS, CITY OF	115		Base	TBL load forecast	2002	3.21	3.66	4.38	3.55	4.83	3.74	3.06	2.46	2.19	2.33	2.41	2.28	3.18
46	CASCADE LOCKS, CITY OF	115		LS	TBL load forecast	2002	3.21	3.66	4.38	3.55	4.83	3.74	3.06	2.46	2.19	2.33	2.41	2.28	3.18
47	CASCADE LOCKS, CITY OF	115		Base	TBL load forecast	2003	3.28	3.74	4.47	3.62	4.93	3.81	3.12	2.51	2.23	2.37	2.46	2.33	3.24
48	CASCADE LOCKS, CITY OF	115		LS	TBL load forecast	2003	3.28	3.74	4.47	3.62	4.93	3.81	3.12	2.51	2.23	2.37	2.46	2.33	3.24
49	CENTRAL ELECTRIC COOP	312	PNGC	Base	TBL load forecast	2002	93.38	80.88	105.57	117.87	104.59	90.01	73.43	67.58	58.04	63.95	66.21	56.48	81.50
50	CENTRAL ELECTRIC COOP	312	PNGC	LS	TBL load forecast	2002	93.38	80.88	105.57	117.87	104.59	90.01	73.43	67.58	58.04	63.95	66.21	56.48	81.50
51	CENTRAL ELECTRIC COOP	312	PNGC	Base	TBL load forecast	2003	94.09	81.50	106.37	118.77	105.38	90.70	73.99	68.10	58.49	64.44	66.72	56.91	82.12
52	CENTRAL ELECTRIC COOP	312	PNGC	LS	TBL load forecast	2003	94.09	81.50	106.37	118.77	105.38	90.70	73.99	68.10	58.49	64.44	66.72	56.91	82.12
53	CENTRAL LINCOLN PUD	207		Base	TBL load forecast	2002	180.12	162.23	211.80	212.43	218.06	200.06	178.60	152.08	124.75	127.49	133.02	135.56	169.68
54	CENTRAL LINCOLN PUD	207		LS	TBL load forecast	2002	181.99	164.10	213.67	214.30	219.93	201.93	180.27	153.75	126.42	129.16	134.69	137.23	171.45
55	CENTRAL LINCOLN PUD	207		Base	TBL load forecast	2003	183.05	164.89	215.22	215.86	221.58	203.30	182.98	156.06	128.31	131.09	136.70	139.28	173.19
56	CENTRAL LINCOLN PUD	207		LS	TBL load forecast	2003	184.72	166.56	216.89	217.53	223.25	204.97	182.98	156.06	128.31	131.09	136.70	139.28	174.03
57	CENTRALIA, CITY OF	119		Base	TBL load forecast	2002	30.77	30.84	37.81	37.02	39.78	32.17	26.04	21.04	17.68	14.41	16.52	20.05	27.01
58	CENTRALIA, CITY OF	119		LS	TBL load forecast	2002	30.77	30.84	37.81	37.02	39.78	32.17	26.04	21.04	17.68	14.41	16.52	20.05	27.01
59	CENTRALIA, CITY OF	119		Base	TBL load forecast	2003	31.08	31.14	38.19	37.39	40.18	32.49	26.30	21.25	17.85	14.55	16.68	20.25	27.28
60	CENTRALIA, CITY OF	119		LS	TBL load forecast	2003	31.08	31.14	38.19	37.39	40.18	32.49	26.30	21.25	17.85	14.55	16.68	20.25	27.28
61	CHENEY, CITY OF	123		Base	TBL load forecast	2002	19.32	20.73	22.83	25.61	26.24	21.09	18.51	16.06	13.73	14.35	14.87	14.33	18.97
62	CHENEY, CITY OF	123		LS	TBL load forecast	2002	19.32	20.73	22.83	25.61	26.24	21.09	18.51	16.06	13.73	14.35	14.87	14.33	18.97
63	CHENEY, CITY OF	123		Base	TBL load forecast	2003	19.74	21.18	23.33	26.16	26.82	21.55	18.92	16.41	14.03	14.66	15.19	14.64	19.39
64	CHENEY, CITY OF	123		LS	TBL load forecast	2003	19.74	21.18	23.33	26.16	26.82	21.55	18.92	16.41	14.03	14.66	15.19	14.64	19.39
65	CHEWELAH, CITY OF	124		Base	TBL load forecast	2002	3.76	4.24	4.78	4.22	4.30	3.41	2.96	2.65	2.44	3.06	3.42	3.15	3.53
66	CHEWELAH, CITY OF	124		LS	TBL load forecast	2002	3.76	4.24	4.78	4.22	4.30	3.41	2.96	2.65	2.44	3.06	3.42	3.15	3.53
67	CHEWELAH, CITY OF	124		Base	TBL load forecast	2003	3.77	4.24	4.78	4.23	4.30	3.42	2.96	2.65	2.44	3.07	3.42	3.16	3.54
68	CHEWELAH, CITY OF	124		LS	TBL load forecast	2003	3.77	4.24	4.78	4.23	4.30	3.42	2.96	2.65	2.44	3.07	3.42	3.16	3.54
69	CLALLAM COUNTY PUD NO 1	213		Base	TBL load forecast	2002	103.05	93.37	123.88	128.33	134.17	109.05	88.03	61.90	56.39	54.14	52.47	54.60	88.28
70	CLALLAM COUNTY PUD NO 1	213		LS	TBL load forecast	2002	103.05	93.37	123.88	128.33	134.17	109.05	88.03	61.90	56.39	54.14	52.47	54.60	88.28
71	CLALLAM COUNTY PUD NO 1	213		Base	TBL load forecast	2003	104.08	94.30	125.12	129.62	135.52	110.14	88.91	62.52	56.96	54.68	53.00	55.15	89.17
72	CLALLAM COUNTY PUD NO 1	213		LS	TBL load forecast	2003	104.08	94.30	125.12	129.62	135.52	110.14	88.91	62.52	56.96	54.68	53.00	55.15	89.17
73	CLARK COUNTY PUD NO 1	216	PPL	Base	12/98 White Book	2002	480.98	575.55	672.71	674.13	701.00	465.72	360.08	351.26	207.68	220.42	295.17	308.65	442.78
74	CLARK COUNTY PUD NO 1	216	PPL	LS	12/98 White Book	2002	624.44	712.88	809.88	811.50	841.92	603.62	501.84	495.57	358.11	350.17	426.73	447.87	582.04
75	CLARK COUNTY PUD NO 1	216	PPL	Base	12/98 White Book	2003	480.98	575.55	672.71	674.13	701.00	465.72	360.08	351.26	207.68	220.42	295.17	308.65	442.78
76	CLARK COUNTY PUD NO 1	216	PPL	LS	12/98 White Book	2003	624.44	712.88	809.88	811.50	841.92	603.62	501.84	495.57	358.11	350.17	426.73	447.87	582.04
77	CLEARWATER POWER COMPANY	315		Base	TBL load forecast	2002	33.34	34.07	41.02	40.78	42.21	34.65	28.82	24.13	20.57	21.16	21.62	20.43	30.23
78	CLEARWATER POWER COMPANY	315		LS	TBL load forecast	2002	33.34	34.07	41.02	40.78	42.21	34.65	28.82	24.13	20.57	21.16	21.62	20.43	30.23
79	CLEARWATER POWER COMPANY	315		Base	TBL load forecast	2003	33.63	34.36	41.37	41.12	42.56	34.95	29.07	24.33	20.75	21.34	21.80	20.61	30.49
80	CLEARWATER POWER COMPANY	315		LS	TBL load forecast	2003	33.63	34.36	41.37	41.12	42.56	34.95	29.07	24.33	20.75	21.34	21.80	20.61	30.49
81	COLUMBIA BASIN ELECTRIC	318		Base	TBL load forecast	2002	16.14	13.35	16.91	13.72	18.44	15.53	17.85	20.29	19.96	17.96	19.05	17.50	17.23
82	COLUMBIA BASIN ELECTRIC	318		LS	TBL load forecast	2002	16.14	13.35	16.91	13.72	18.44	15.53	17.85	20.29	19.96	17.96	19.05	17.50	17.23
83	COLUMBIA BASIN ELECTRIC	318		Base	TBL load forecast	2003	16.46	13.61	17.24	13.99	18.81	15.84	18.21	20.69	20.36	18.32	19.43	17.84	17.57
84	COLUMBIA BASIN ELECTRIC	318		LS	TBL load forecast	2003	16.46	13.61	17.24	13.99	18.81	15.84	18.21	20.69	20.36	18.32	19.43	17.84	17.57
85	COLUMBIA POWER COOP	321		Base	TBL load forecast	2002	4.02	3.47	4.97	5.17	5.33	3.87	3.40	3.43	3.91	4.86	5.11	4.14	4.31
86	COLUMBIA POWER COOP	321		LS	TBL load forecast	2002	4.02	3.47	4.97	5.17	5.33	3.87	3.40	3.43	3.91	4.86	5.11	4.14	4.31
87	COLUMBIA POWER COOP	321		Base	TBL load forecast	2003	4.05	3.50	5.02	5.21	5.37	3.90	3.43	3.46	3.94	4.89	5.15	4.18	4.34
88	COLUMBIA POWER COOP	321		LS	TBL load forecast	2003	4.05	3.50	5.02	5.21	5.37	3.90	3.43	3.46	3.94	4.89	5.15	4.18	4.34

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
89	COLUMBIA RIVER PUD	221		Base	TBL load forecast	2002	46.91	47.51	51.87	54.01	56.53	48.44	45.02	38.28	31.85	40.02	38.78	39.37	44.88
90	COLUMBIA RIVER PUD	221		LS	TBL load forecast	2002	46.91	47.51	51.87	54.01	56.53	48.44	45.02	38.28	31.85	40.02	38.78	39.37	44.88
91	COLUMBIA RIVER PUD	221		Base	TBL load forecast	2003	47.69	48.30	52.73	54.91	57.48	49.25	45.77	38.92	32.38	40.68	39.43	40.03	45.63
92	COLUMBIA RIVER PUD	221		LS	TBL load forecast	2003	47.69	48.30	52.73	54.91	57.48	49.25	45.77	38.92	32.38	40.68	39.43	40.03	45.63
93	COLUMBIA RURAL ELECTRIC	324		Base	TBL load forecast	2002	24.69	18.59	21.62	21.97	23.99	19.18	38.29	53.38	75.70	103.37	107.26	62.50	47.54
94	COLUMBIA RURAL ELECTRIC	324		LS	TBL load forecast	2002	24.69	18.59	21.62	21.97	23.99	19.18	38.29	53.38	75.70	103.37	107.26	62.50	47.54
95	COLUMBIA RURAL ELECTRIC	324		Base	TBL load forecast	2003	25.40	19.13	22.24	22.60	24.68	19.74	39.40	54.92	77.89	106.36	110.37	64.31	48.92
96	COLUMBIA RURAL ELECTRIC	324		LS	TBL load forecast	2003	25.40	19.13	22.24	22.60	24.68	19.74	39.40	54.92	77.89	106.36	110.37	64.31	48.92
97	CONSUMERS POWER INC	327	PNGC	Base	TBL load forecast	2002	72.12	72.01	91.32	90.06	100.44	77.21	68.42	54.83	43.93	50.61	56.25	45.14	68.53
98	CONSUMERS POWER INC	327	PNGC	LS	TBL load forecast	2002	72.12	72.01	91.32	90.06	100.44	77.21	68.42	54.83	43.93	50.61	56.25	45.14	68.53
99	CONSUMERS POWER INC	327	PNGC	Base	TBL load forecast	2003	74.64	74.53	94.52	93.21	103.95	79.92	70.81	56.75	45.47	52.38	58.22	46.72	70.93
100	CONSUMERS POWER INC	327	PNGC	LS	TBL load forecast	2003	74.64	74.53	94.52	93.21	103.95	79.92	70.81	56.75	45.47	52.38	58.22	46.72	70.93
101	COOS-CURRY ELECTRIC COOP	330	PNGC	Base	TBL load forecast	2002	57.02	58.27	66.22	65.15	72.83	68.95	55.74	46.78	35.14	35.77	35.07	34.50	52.62
102	COOS-CURRY ELECTRIC COOP	330	PNGC	LS	TBL load forecast	2002	58.11	59.36	67.31	66.24	73.92	70.04	56.72	47.76	36.12	36.75	36.05	35.48	53.66
103	COOS-CURRY ELECTRIC COOP	330	PNGC	Base	TBL load forecast	2003	58.15	59.42	67.51	66.41	74.22	70.28	57.70	48.59	36.75	37.39	36.68	36.10	54.10
104	COOS-CURRY ELECTRIC COOP	330	PNGC	LS	TBL load forecast	2003	59.13	60.40	68.49	67.39	75.20	71.26	57.70	48.59	36.75	37.39	36.68	36.10	54.59
105	COULEE DAM, CITY OF	125		Base	TBL load forecast	2002	2.35	3.50	4.43	4.88	4.97	3.52	2.32	1.88	1.31	1.50	1.79	1.44	2.82
106	COULEE DAM, CITY OF	125		LS	TBL load forecast	2002	2.52	3.67	4.60	5.05	5.14	3.69	2.47	2.03	1.46	1.65	1.94	1.59	2.98
107	COULEE DAM, CITY OF	125		Base	TBL load forecast	2003	2.38	3.55	4.48	4.94	5.02	3.56	2.48	2.04	1.46	1.66	1.95	1.60	2.93
108	COULEE DAM, CITY OF	125		LS	TBL load forecast	2003	2.53	3.70	4.63	5.09	5.17	3.71	2.48	2.04	1.46	1.66	1.95	1.60	3.00
109	DECLO, CITY OF	127		Base	TBL load forecast	2002	0.49	0.53	0.63	0.67	0.64	0.54	0.50	0.39	0.30	0.33	0.35	0.37	0.48
110	DECLO, CITY OF	127		LS	TBL load forecast	2002	0.49	0.53	0.63	0.67	0.64	0.54	0.50	0.39	0.30	0.33	0.35	0.37	0.48
111	DECLO, CITY OF	127		Base	TBL load forecast	2003	0.49	0.53	0.64	0.67	0.64	0.54	0.51	0.40	0.31	0.33	0.35	0.37	0.48
112	DECLO, CITY OF	127		LS	TBL load forecast	2003	0.49	0.53	0.64	0.67	0.64	0.54	0.51	0.40	0.31	0.33	0.35	0.37	0.48
113	DOUGLAS ELECTRIC COOP	333	PNGC	Base	TBL load forecast	2002	28.11	28.08	36.28	35.73	36.64	33.09	27.44	21.26	17.49	19.93	21.27	20.07	27.12
114	DOUGLAS ELECTRIC COOP	333	PNGC	LS	TBL load forecast	2002	28.11	28.08	36.28	35.73	36.64	33.09	27.44	21.26	17.49	19.93	21.27	20.07	27.12
115	DOUGLAS ELECTRIC COOP	333	PNGC	Base	TBL load forecast	2003	28.79	28.75	37.15	36.59	37.52	33.89	28.10	21.77	17.91	20.41	21.78	20.55	27.77
116	DOUGLAS ELECTRIC COOP	333	PNGC	LS	TBL load forecast	2003	28.79	28.75	37.15	36.59	37.52	33.89	28.10	21.77	17.91	20.41	21.78	20.55	27.77
117	DRAIN, CITY OF	128		Base	TBL load forecast	2002	4.13	3.98	4.78	5.01	5.14	4.27	4.01	3.54	3.05	3.23	3.15	3.22	3.96
118	DRAIN, CITY OF	128		LS	TBL load forecast	2002	4.13	3.98	4.78	5.01	5.14	4.27	4.01	3.54	3.05	3.23	3.15	3.22	3.96
119	DRAIN, CITY OF	128		Base	TBL load forecast	2003	4.21	4.06	4.87	5.11	5.24	4.35	4.09	3.61	3.11	3.29	3.21	3.28	4.04
120	DRAIN, CITY OF	128		LS	TBL load forecast	2003	4.21	4.06	4.87	5.11	5.24	4.35	4.09	3.61	3.11	3.29	3.21	3.28	4.04
121	EAST END MUTUAL ELECTRIC	335		Base	TBL load forecast	2002	2.26	2.42	3.43	2.81	1.75	2.03	2.27	1.93	2.34	3.71	3.61	2.49	2.59
122	EAST END MUTUAL ELECTRIC	335		LS	TBL load forecast	2002	2.26	2.42	3.43	2.81	1.75	2.03	2.27	1.93	2.34	3.71	3.61	2.49	2.59
123	EAST END MUTUAL ELECTRIC	335		Base	TBL load forecast	2003	2.28	2.44	3.46	2.84	1.76	2.05	2.29	1.94	2.37	3.74	3.64	2.51	2.61
124	EAST END MUTUAL ELECTRIC	335		LS	TBL load forecast	2003	2.28	2.44	3.46	2.84	1.76	2.05	2.29	1.94	2.37	3.74	3.64	2.51	2.61
125	EATONVILLE, TOWN OF	131		Base	TBL load forecast	2002	4.94	5.37	6.38	6.76	6.63	4.41	3.97	3.55	2.50	2.34	2.32	3.38	4.38
126	EATONVILLE, TOWN OF	131		LS	TBL load forecast	2002	4.94	5.37	6.38	6.76	6.63	4.41	3.97	3.55	2.50	2.34	2.32	3.38	4.38
127	EATONVILLE, TOWN OF	131		Base	TBL load forecast	2003	5.11	5.56	6.60	7.00	6.86	4.56	4.11	3.68	2.59	2.42	2.40	3.49	4.53
128	EATONVILLE, TOWN OF	131		LS	TBL load forecast	2003	5.11	5.56	6.60	7.00	6.86	4.56	4.11	3.68	2.59	2.42	2.40	3.49	4.53
129	ELLENSBURG, CITY OF	133		Base	TBL load forecast	2002	31.32	32.04	33.68	37.15	35.54	29.45	27.25	28.54	23.24	24.34	28.37	28.15	29.92
130	ELLENSBURG, CITY OF	133		LS	TBL load forecast	2002	31.32	32.04	33.68	37.15	35.54	29.45	27.25	28.54	23.24	24.34	28.37	28.15	29.92
131	ELLENSBURG, CITY OF	133		Base	TBL load forecast	2003	31.82	32.55	34.22	37.74	36.11	29.92	27.68	29.00	23.61	24.72	28.82	28.60	30.40
132	ELLENSBURG, CITY OF	133		LS	TBL load forecast	2003	31.82	32.55	34.22	37.74	36.11	29.92	27.68	29.00	23.61	24.72	28.82	28.60	30.40

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
133	ELMHURST MUTUAL POWER & LT	334		Base	TBL load forecast	2002	46.61	48.08	57.98	61.36	65.17	49.87	40.00	29.44	21.88	20.42	22.70	23.21	40.56
134	ELMHURST MUTUAL POWER & LT	334		LS	TBL load forecast	2002	46.61	48.08	57.98	61.36	65.17	49.87	40.00	29.44	21.88	20.42	22.70	23.21	40.56
135	ELMHURST MUTUAL POWER & LT	334		Base	TBL load forecast	2003	47.51	49.02	59.11	62.55	66.44	50.84	40.77	30.01	22.31	20.82	23.14	23.66	41.35
136	ELMHURST MUTUAL POWER & LT	334		LS	TBL load forecast	2003	47.51	49.02	59.11	62.55	66.44	50.84	40.77	30.01	22.31	20.82	23.14	23.66	41.35
137	EMERALD PUD	229		Base	TBL load forecast	2002	77.66	74.82	94.22	96.14	103.07	82.11	72.46	57.47	51.64	59.58	59.01	55.16	73.61
138	EMERALD PUD	229		LS	TBL load forecast	2002	77.66	74.82	94.22	96.14	103.07	82.11	72.46	57.47	51.64	59.58	59.01	55.16	73.61
139	EMERALD PUD	229		Base	TBL load forecast	2003	79.53	76.62	96.49	98.45	105.55	84.09	74.20	58.86	52.88	61.01	60.43	56.48	75.38
140	EMERALD PUD	229		LS	TBL load forecast	2003	79.53	76.62	96.49	98.45	105.55	84.09	74.20	58.86	52.88	61.01	60.43	56.48	75.38
141	ENERGY NW INC., (FEC)	336		Base	20% of Flathead	2002	0.00	6.38	8.18	10.58	13.13	6.86	3.99	0.08	0.30	0.00	0.00	0.00	4.13
142	ENERGY NW INC., (FEC)	336		Base	20% of Flathead	2003	0.42	6.98	8.83	11.30	13.93	7.48	4.55	0.53	0.75	0.00	0.06	0.00	4.57
143	ENERGY NW INC., (WPPSS)	195		Base	TBL load forecast	2002	4.38	3.93	5.43	5.45	5.31	4.28	4.02	3.25	3.05	3.81	3.84	3.55	4.19
144	ENERGY NW INC., (WPPSS)	195		LS	TBL load forecast	2002	4.38	3.93	5.43	5.45	5.31	4.28	4.02	3.25	3.05	3.81	3.84	3.55	4.19
145	ENERGY NW INC., (WPPSS)	195		Base	TBL load forecast	2003	4.40	3.95	5.46	5.48	5.33	4.30	4.04	3.27	3.07	3.83	3.86	3.57	4.21
146	ENERGY NW INC., (WPPSS)	195		LS	TBL load forecast	2003	4.40	3.95	5.46	5.48	5.33	4.30	4.04	3.27	3.07	3.83	3.86	3.57	4.21
147	FALL RIVER RURAL ELECTRIC	337		Base	TBL load forecast	2002	25.02	28.30	36.09	34.61	34.88	26.29	20.83	20.92	36.72	43.34	35.13	21.05	30.27
148	FALL RIVER RURAL ELECTRIC	337		LS	TBL load forecast	2002	25.02	28.30	36.09	34.61	34.88	26.29	20.83	20.92	36.72	43.34	35.13	21.05	30.27
149	FALL RIVER RURAL ELECTRIC	337		Base	TBL load forecast	2003	25.36	28.68	36.57	35.07	35.34	26.65	21.11	21.20	37.21	43.93	35.60	21.34	30.67
150	FALL RIVER RURAL ELECTRIC	337		LS	TBL load forecast	2003	25.36	28.68	36.57	35.07	35.34	26.65	21.11	21.20	37.21	43.93	35.60	21.34	30.67
151	FARMERS ELECTRIC COOP	338		Base	TBL load forecast	2002	0.70	0.79	0.96	1.05	0.99	0.79	0.61	0.54	0.40	0.49	0.48	0.41	0.68
152	FARMERS ELECTRIC COOP	338		LS	TBL load forecast	2002	0.70	0.79	0.96	1.05	0.99	0.79	0.61	0.54	0.40	0.49	0.48	0.41	0.68
153	FARMERS ELECTRIC COOP	338		Base	TBL load forecast	2003	0.71	0.81	0.98	1.07	1.01	0.81	0.62	0.55	0.41	0.50	0.49	0.42	0.70
154	FARMERS ELECTRIC COOP	338		LS	TBL load forecast	2003	0.71	0.81	0.98	1.07	1.01	0.81	0.62	0.55	0.41	0.50	0.49	0.42	0.70
155	FERRY COUNTY PUD NO 1	230		Base	TBL load forecast	2002	17.09	18.38	20.13	22.37	21.99	18.15	15.93	14.64	13.03	12.81	13.37	13.13	16.75
156	FERRY COUNTY PUD NO 1	230		LS	TBL load forecast	2002	17.09	18.38	20.13	22.37	21.99	18.15	15.93	14.64	13.03	12.81	13.37	13.13	16.75
157	FERRY COUNTY PUD NO 1	230		Base	TBL load forecast	2003	17.21	18.51	20.27	22.53	22.15	18.28	16.04	14.74	13.12	12.90	13.46	13.22	16.87
158	FERRY COUNTY PUD NO 1	230		LS	TBL load forecast	2003	17.21	18.51	20.27	22.53	22.15	18.28	16.04	14.74	13.12	12.90	13.46	13.22	16.87
159	FIRCREST, TOWN OF	140		Base	TBL load forecast	2002	7.00	8.08	9.35	9.10	9.36	7.70	6.40	4.89	3.69	3.81	3.76	3.75	6.41
160	FIRCREST, TOWN OF	140		LS	TBL load forecast	2002	7.00	8.08	9.35	9.10	9.36	7.70	6.40	4.89	3.69	3.81	3.76	3.75	6.41
161	FIRCREST, TOWN OF	140		Base	TBL load forecast	2003	7.02	8.10	9.37	9.12	9.38	7.72	6.41	4.90	3.69	3.82	3.77	3.76	6.42
162	FIRCREST, TOWN OF	140		LS	TBL load forecast	2003	7.02	8.10	9.37	9.12	9.38	7.72	6.41	4.90	3.69	3.82	3.77	3.76	6.42
163	FOREST GROVE, CITY OF	142		Base	TBL load forecast	2002	32.51	31.35	40.39	41.45	45.65	33.21	27.70	19.87	20.86	21.25	19.07	22.36	29.64
164	FOREST GROVE, CITY OF	142		LS	TBL load forecast	2002	41.50	40.34	49.38	50.44	54.64	42.20	36.61	28.78	29.77	30.16	27.98	31.27	38.59
165	FOREST GROVE, CITY OF	142		Base	TBL load forecast	2003	33.17	31.99	41.16	42.23	46.49	33.88	28.82	20.88	21.88	22.28	20.07	23.40	30.52
166	FOREST GROVE, CITY OF	142		LS	TBL load forecast	2003	42.08	40.90	50.07	51.14	55.40	42.79	37.12	29.18	30.18	30.58	28.37	31.70	39.13
167	GLACIER ELECTRIC COOP	340		Base	TBL load forecast	2002	23.66	26.50	28.65	30.15	30.26	26.26	22.41	20.62	20.30	19.41	18.83	19.40	23.87
168	GLACIER ELECTRIC COOP	340		LS	TBL load forecast	2002	23.66	26.50	28.65	30.15	30.26	26.26	22.41	20.62	20.30	19.41	18.83	19.40	23.87
169	GLACIER ELECTRIC COOP	340		Base	TBL load forecast	2003	23.95	26.82	28.99	30.51	30.63	26.57	22.68	20.87	20.55	19.64	19.05	19.63	24.16
170	GLACIER ELECTRIC COOP	340		LS	TBL load forecast	2003	23.95	26.82	28.99	30.51	30.63	26.57	22.68	20.87	20.55	19.64	19.05	19.63	24.16
171	HARNEY ELECTRIC COO	341		Base	TBL load forecast	2002	9.65	7.69	10.19	11.90	11.22	11.11	13.53	20.81	21.54	31.29	30.25	27.71	17.24
172	HARNEY ELECTRIC COO	341		LS	TBL load forecast	2002	9.65	7.69	10.19	11.90	11.22	11.11	13.53	20.81	21.54	31.29	30.25	27.71	17.24
173	HARNEY ELECTRIC COO	341		Base	TBL load forecast	2003	9.70	7.73	10.24	11.96	11.28	11.16	13.59	20.91	21.65	31.45	30.40	27.85	17.33
174	HARNEY ELECTRIC COO	341		LS	TBL load forecast	2003	9.70	7.73	10.24	11.96	11.28	11.16	13.59	20.91	21.65	31.45	30.40	27.85	17.33
175	HEYBURN, CITY OF	150		Base	TBL load forecast	2002	15.09	15.17	15.88	16.50	16.48	16.09	8.83	13.27	13.60	13.70	12.86	13.53	14.25
176	HEYBURN, CITY OF	150		LS	TBL load forecast	2002	15.09	15.17	15.88	16.50	16.48	16.09	8.83	13.27	13.60	13.70	12.86	13.53	14.25

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
177	HEYBURN, CITY OF	150		Base	TBL load forecast	2003	15.18	15.26	15.97	16.59	16.57	16.19	8.89	13.34	13.68	13.78	12.93	13.61	14.33
178	HEYBURN, CITY OF	150		LS	TBL load forecast	2003	15.18	15.26	15.97	16.59	16.57	16.19	8.89	13.34	13.68	13.78	12.93	13.61	14.33
179	HOOD RIVER ELECTRIC COOP	342		Base	TBL load forecast	2002	19.27	19.51	20.10	21.67	21.52	18.06	15.96	12.07	9.72	9.48	12.94	15.46	16.31
180	HOOD RIVER ELECTRIC COOP	342		LS	TBL load forecast	2002	19.27	19.51	20.10	21.67	21.52	18.06	15.96	12.07	9.72	9.48	12.94	15.46	16.31
181	HOOD RIVER ELECTRIC COOP	342		Base	TBL load forecast	2003	19.50	19.74	20.34	21.93	21.77	18.28	16.16	12.22	9.83	9.59	13.10	15.65	16.51
182	HOOD RIVER ELECTRIC COOP	342		LS	TBL load forecast	2003	19.50	19.74	20.34	21.93	21.77	18.28	16.16	12.22	9.83	9.59	13.10	15.65	16.51
183	IDAHO COUNTY LIGHT & POWER	345		Base	TBL load forecast	2002	7.32	7.48	9.57	9.32	9.92	7.86	6.26	5.52	4.36	4.90	4.87	4.24	6.80
184	IDAHO COUNTY LIGHT & POWER	345		LS	TBL load forecast	2002	7.52	7.68	9.77	9.52	10.12	8.06	6.44	5.70	4.54	5.08	5.05	4.42	6.99
185	IDAHO COUNTY LIGHT & POWER	345		Base	TBL load forecast	2003	7.37	7.53	9.63	9.39	9.98	7.92	6.47	5.73	4.56	5.10	5.07	4.43	6.93
186	IDAHO COUNTY LIGHT & POWER	345		LS	TBL load forecast	2003	7.55	7.71	9.81	9.57	10.16	8.10	6.47	5.73	4.56	5.10	5.07	4.43	7.02
187	INLAND POWER & LIGHT CO	348		Base	TBL load forecast	2002	135.03	139.09	162.63	168.44	162.63	142.28	127.94	114.66	108.65	102.26	110.17	112.56	132.20
188	INLAND POWER & LIGHT CO	348		LS	TBL load forecast	2002	136.15	140.21	163.75	169.56	163.75	143.40	128.94	115.66	109.65	103.26	111.17	113.56	133.26
189	INLAND POWER & LIGHT CO	348		Base	TBL load forecast	2003	135.87	139.95	163.65	169.50	163.65	143.17	129.61	116.24	110.19	103.76	111.72	114.12	133.45
190	INLAND POWER & LIGHT CO	348		LS	TBL load forecast	2003	136.87	140.95	164.65	170.50	164.65	144.17	129.61	116.24	110.19	103.76	111.72	114.12	133.95
191	KITTITAS COUNTY PUD NO 1	246		Base	TBL load forecast	2002	6.21	6.71	8.64	9.15	9.46	6.11	3.62	3.52	2.70	3.36	3.49	2.35	5.44
192	KITTITAS COUNTY PUD NO 1	246		LS	TBL load forecast	2002	10.05	10.55	12.48	12.99	13.30	9.95	7.45	7.35	6.53	7.19	7.32	6.18	9.28
193	KITTITAS COUNTY PUD NO 1	246		Base	TBL load forecast	2003	6.23	6.73	8.66	9.17	9.49	6.13	3.66	3.56	2.73	3.40	3.52	2.38	5.47
194	KITTITAS COUNTY PUD NO 1	246		LS	TBL load forecast	2003	10.06	10.56	12.49	13.00	13.32	9.96	7.46	7.36	6.53	7.20	7.32	6.18	9.29
195	KOOTENAI ELECTRIC COOP	351		Base	TBL load forecast	2002	44.70	48.02	57.69	58.05	60.79	48.75	39.24	33.69	30.08	31.64	31.54	28.79	42.75
196	KOOTENAI ELECTRIC COOP	351		LS	TBL load forecast	2002	44.70	48.02	57.69	58.05	60.79	48.75	39.24	33.69	30.08	31.64	31.54	28.79	42.75
197	KOOTENAI ELECTRIC COOP	351		Base	TBL load forecast	2003	45.24	48.60	58.38	58.75	61.52	49.34	39.71	34.09	30.44	32.02	31.92	29.13	43.26
198	KOOTENAI ELECTRIC COOP	351		LS	TBL load forecast	2003	45.24	48.60	58.38	58.75	61.52	49.34	39.71	34.09	30.44	32.02	31.92	29.13	43.26
199	LAKEVIEW LIGHT & POWER CO	353		Base	TBL load forecast	2002	42.00	43.21	53.30	54.08	53.35	45.35	40.68	35.13	32.76	36.08	33.26	32.63	41.82
200	LAKEVIEW LIGHT & POWER CO	353		LS	TBL load forecast	2002	42.00	43.21	53.30	54.08	53.35	45.35	40.68	35.13	32.76	36.08	33.26	32.63	41.82
201	LAKEVIEW LIGHT & POWER CO	353		Base	TBL load forecast	2003	42.15	43.36	53.50	54.27	53.54	45.51	40.83	35.26	32.88	36.21	33.38	32.75	41.97
202	LAKEVIEW LIGHT & POWER CO	353		LS	TBL load forecast	2003	42.15	43.36	53.50	54.27	53.54	45.51	40.83	35.26	32.88	36.21	33.38	32.75	41.97
203	LANE ELECTRIC COOPERATIVE	354	PNGC	Base	TBL load forecast	2002	43.99	44.13	58.76	58.18	64.40	50.91	39.75	29.36	21.65	21.97	22.85	21.16	39.76
204	LANE ELECTRIC COOPERATIVE	354	PNGC	LS	TBL load forecast	2002	44.74	44.88	59.51	58.93	65.15	51.66	40.42	30.03	22.32	22.64	23.52	21.83	40.47
205	LANE ELECTRIC COOPERATIVE	354	PNGC	Base	TBL load forecast	2003	44.98	45.12	60.05	59.46	65.81	52.05	41.25	30.64	22.77	23.10	24.00	22.28	40.96
206	LANE ELECTRIC COOPERATIVE	354	PNGC	LS	TBL load forecast	2003	45.65	45.79	60.72	60.13	66.48	52.72	41.25	30.64	22.77	23.10	24.00	22.28	41.29
207	LEWIS COUNTY PUD NO 1	253		Base	TBL load forecast	2002	179.52	168.40	191.41	181.89	206.99	172.26	148.62	131.03	110.68	116.92	114.74	109.88	152.70
208	LEWIS COUNTY PUD NO 1	253		LS	TBL load forecast	2002	179.52	168.40	191.41	181.89	206.99	172.26	148.62	131.03	110.68	116.92	114.74	109.88	152.70
209	LEWIS COUNTY PUD NO 1	253		Base	TBL load forecast	2003	179.97	168.82	191.89	182.34	207.51	172.69	149.00	131.36	110.96	117.22	115.03	110.15	153.08
210	LEWIS COUNTY PUD NO 1	253		LS	TBL load forecast	2003	179.97	168.82	191.89	182.34	207.51	172.69	149.00	131.36	110.96	117.22	115.03	110.15	153.08
211	LINCOLN ELECTRIC COOP	357		Base	TBL load forecast	2002	13.86	12.74	17.34	21.12	20.83	17.38	15.43	12.97	10.68	11.55	10.83	9.26	14.50
212	LINCOLN ELECTRIC COOP	357		LS	TBL load forecast	2002	14.05	12.93	17.53	21.31	21.02	17.57	15.60	13.14	10.85	11.72	11.00	9.43	14.68
213	LINCOLN ELECTRIC COOP	357		Base	TBL load forecast	2003	13.90	12.79	17.39	21.19	20.89	17.44	15.63	13.16	10.87	11.75	11.02	9.45	14.62
214	LINCOLN ELECTRIC COOP	357		LS	TBL load forecast	2003	14.07	12.96	17.56	21.36	21.06	17.61	15.63	13.16	10.87	11.75	11.02	9.45	14.71
215	LOST RIVER ELECTRIC COOP	359	PNGC	Base	TBL load forecast	2002	4.37	5.42	7.00	7.26	6.86	4.64	3.93	6.61	11.30	17.08	14.36	7.37	8.02
216	LOST RIVER ELECTRIC COOP	359	PNGC	LS	TBL load forecast	2002	4.37	5.42	7.00	7.26	6.86	4.64	3.93	6.61	11.30	17.08	14.36	7.37	8.02
217	LOST RIVER ELECTRIC COOP	359	PNGC	Base	TBL load forecast	2003	4.39	5.45	7.03	7.29	6.90	4.67	3.95	6.64	11.36	17.17	14.43	7.41	8.06
218	LOST RIVER ELECTRIC COOP	359	PNGC	LS	TBL load forecast	2003	4.39	5.45	7.03	7.29	6.90	4.67	3.95	6.64	11.36	17.17	14.43	7.41	8.06
219	LOWER VALLEY POWER & LT	360		Base	TBL load forecast	2002	79.44	91.05	126.31	125.96	126.44	91.99	69.97	58.67	46.90	61.31	54.15	49.26	81.79
220	LOWER VALLEY POWER & LT	360		LS	TBL load forecast	2002	79.44	91.05	126.31	125.96	126.44	91.99	69.97	58.67	46.90	61.31	54.15	49.26	81.79

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
221	LOWER VALLEY POWER & LT	360		Base	TBL load forecast	2003	81.03	92.87	128.84	128.48	128.98	93.84	71.37	59.85	47.84	62.54	55.24	50.24	83.43
222	LOWER VALLEY POWER & LT	360		LS	TBL load forecast	2003	81.03	92.87	128.84	128.48	128.98	93.84	71.37	59.85	47.84	62.54	55.24	50.24	83.43
223	MASON COUNTY PUD 1	257		Base	TBL load forecast	2002	9.95	9.65	12.91	13.72	13.22	10.61	8.80	7.45	5.62	5.76	5.60	5.20	9.04
224	MASON COUNTY PUD 1	257		LS	TBL load forecast	2002	9.95	9.65	12.91	13.72	13.22	10.61	8.80	7.45	5.62	5.76	5.60	5.20	9.04
225	MASON COUNTY PUD 1	257		Base	TBL load forecast	2003	10.00	9.70	12.97	13.78	13.29	10.66	8.84	7.49	5.64	5.79	5.63	5.22	9.08
226	MASON COUNTY PUD 1	257		LS	TBL load forecast	2003	10.00	9.70	12.97	13.78	13.29	10.66	8.84	7.49	5.64	5.79	5.63	5.22	9.08
227	MCCLEARY, CITY OF	154		Base	TBL load forecast	2002	6.70	6.50	7.78	7.78	8.20	7.13	6.34	5.69	4.92	4.89	4.61	4.66	6.27
228	MCCLEARY, CITY OF	154		LS	TBL load forecast	2002	6.70	6.50	7.78	7.78	8.20	7.13	6.34	5.69	4.92	4.89	4.61	4.66	6.27
229	MCCLEARY, CITY OF	154		Base	TBL load forecast	2003	6.77	6.57	7.86	7.86	8.30	7.21	6.41	5.75	4.97	4.95	4.66	4.71	6.34
230	MCCLEARY, CITY OF	154		LS	TBL load forecast	2003	6.77	6.57	7.86	7.86	8.30	7.21	6.41	5.75	4.97	4.95	4.66	4.71	6.34
231	MCMINNVILLE, CITY OF	155		Base	TBL load forecast	2002	120.77	133.16	136.91	133.63	159.56	114.00	119.02	111.26	103.96	99.66	89.79	83.13	117.07
232	MCMINNVILLE, CITY OF	155		LS	TBL load forecast	2002	121.65	134.04	137.79	134.51	160.44	114.88	119.80	112.04	104.74	100.44	90.57	83.91	117.90
233	MCMINNVILLE, CITY OF	155		Base	TBL load forecast	2003	123.28	135.92	139.74	136.40	162.85	116.38	122.18	114.27	106.82	102.43	92.37	85.58	119.85
234	MCMINNVILLE, CITY OF	155		LS	TBL load forecast	2003	124.06	136.70	140.52	137.18	163.63	117.16	122.18	114.27	106.82	102.43	92.37	85.58	120.24
235	MIDSTATE ELECTRIC COOP	361		Base	TBL load forecast	2002	52.04	55.36	59.57	58.21	61.06	53.05	44.61	55.40	40.30	45.75	43.51	43.83	51.06
236	MIDSTATE ELECTRIC COOP	361		LS	TBL load forecast	2002	52.04	55.36	59.57	58.21	61.06	53.05	44.61	55.40	40.30	45.75	43.51	43.83	51.06
237	MIDSTATE ELECTRIC COOP	361		Base	TBL load forecast	2003	53.28	56.68	60.99	59.59	62.52	54.31	45.67	56.72	41.25	46.84	44.55	44.88	52.27
238	MIDSTATE ELECTRIC COOP	361		LS	TBL load forecast	2003	53.28	56.68	60.99	59.59	62.52	54.31	45.67	56.72	41.25	46.84	44.55	44.88	52.27
239	MILTON, TOWN OF	158		Base	TBL load forecast	2002	8.99	10.12	11.80	11.83	11.93	9.71	7.99	6.38	5.59	5.74	5.47	5.71	8.44
240	MILTON, TOWN OF	158		LS	TBL load forecast	2002	8.99	10.12	11.80	11.83	11.93	9.71	7.99	6.38	5.59	5.74	5.47	5.71	8.44
241	MILTON, TOWN OF	158		Base	TBL load forecast	2003	9.05	10.19	11.87	11.90	12.00	9.77	8.04	6.42	5.62	5.77	5.51	5.74	8.49
242	MILTON, TOWN OF	158		LS	TBL load forecast	2003	9.05	10.19	11.87	11.90	12.00	9.77	8.04	6.42	5.62	5.77	5.51	5.74	8.49
243	MILTON-FREEWATER, CITY OF	159		Base	TBL load forecast	2002	10.58	11.96	16.16	18.47	21.52	12.19	6.66	5.30	4.34	9.13	10.90	7.50	11.23
244	MILTON-FREEWATER, CITY OF	159		LS	TBL load forecast	2002	19.11	20.49	24.69	27.00	30.05	20.72	15.17	13.81	12.85	17.64	19.41	16.01	19.75
245	MILTON-FREEWATER, CITY OF	159		Base	TBL load forecast	2003	10.99	12.40	16.68	19.05	22.15	12.63	7.08	5.69	4.72	9.60	11.41	7.94	11.70
246	MILTON-FREEWATER, CITY OF	159		LS	TBL load forecast	2003	19.50	20.91	25.19	27.56	30.66	21.14	15.48	14.09	13.12	18.00	19.81	16.34	20.15
247	MINIDOKA, CITY OF	161		Base	TBL load forecast	2002	0.11	0.12	0.15	0.16	0.14	0.10	0.08	0.05	0.07	0.08	0.08	0.08	0.10
248	MINIDOKA, CITY OF	161		LS	TBL load forecast	2002	0.11	0.12	0.15	0.16	0.14	0.10	0.08	0.05	0.07	0.08	0.08	0.08	0.10
249	MINIDOKA, CITY OF	161		Base	TBL load forecast	2003	0.11	0.12	0.15	0.16	0.14	0.10	0.09	0.05	0.07	0.08	0.08	0.08	0.10
250	MINIDOKA, CITY OF	161		LS	TBL load forecast	2003	0.11	0.12	0.15	0.16	0.14	0.10	0.09	0.05	0.07	0.08	0.08	0.08	0.10
251	MISSOULA ELECTRIC COOP	364		Base	TBL load forecast	2002	22.38	26.18	29.57	30.87	33.01	25.82	20.88	19.52	18.04	19.56	19.29	16.45	23.46
252	MISSOULA ELECTRIC COOP	364		LS	TBL load forecast	2002	22.55	26.35	29.74	31.04	33.18	25.99	21.03	19.67	18.19	19.71	19.44	16.60	23.62
253	MISSOULA ELECTRIC COOP	364		Base	TBL load forecast	2003	22.81	26.68	30.14	31.46	33.64	26.32	21.42	20.03	18.52	20.08	19.80	16.91	23.98
254	MISSOULA ELECTRIC COOP	364		LS	TBL load forecast	2003	22.96	26.83	30.29	31.61	33.79	26.47	21.42	20.03	18.52	20.08	19.80	16.91	24.06
255	MODERN ELECTRIC WATER CO	366		Base	TBL load forecast	2002	46.13	52.62	59.05	54.78	59.29	48.92	45.72	42.53	45.41	50.05	54.19	44.77	50.29
256	MODERN ELECTRIC WATER CO	366		LS	TBL load forecast	2002	46.13	52.62	59.05	54.78	59.29	48.92	45.72	42.53	45.41	50.05	54.19	44.77	50.29
257	MODERN ELECTRIC WATER CO	366		Base	TBL load forecast	2003	47.75	54.46	61.11	56.69	61.37	50.63	47.32	44.01	47.00	51.80	56.08	46.34	52.05
258	MODERN ELECTRIC WATER CO	366		LS	TBL load forecast	2003	47.75	54.46	61.11	56.69	61.37	50.63	47.32	44.01	47.00	51.80	56.08	46.34	52.05
259	MONMOUTH, CITY OF	163		Base	TBL load forecast	2002	11.61	12.12	14.47	15.31	17.17	12.08	10.79	8.71	6.88	7.14	7.12	7.09	10.87
260	MONMOUTH, CITY OF	163		LS	TBL load forecast	2002	11.61	12.12	14.47	15.31	17.17	12.08	10.79	8.71	6.88	7.14	7.12	7.09	10.87
261	MONMOUTH, CITY OF	163		Base	TBL load forecast	2003	11.70	12.22	14.59	15.43	17.31	12.17	10.88	8.79	6.93	7.20	7.18	7.15	10.96
262	MONMOUTH, CITY OF	163		LS	TBL load forecast	2003	11.70	12.22	14.59	15.43	17.31	12.17	10.88	8.79	6.93	7.20	7.18	7.15	10.96
263	NESPELEM VALLEY ELECTRIC	367		Base	TBL load forecast	2002	6.23	6.04	7.44	8.51	8.41	6.48	5.96	5.41	6.33	6.64	7.74	6.12	6.78
264	NESPELEM VALLEY ELECTRIC	367		LS	TBL load forecast	2002	6.32	6.13	7.53	8.60	8.50	6.57	6.04	5.49	6.41	6.72	7.82	6.20	6.86

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
265	NESPELEM VALLEY ELECTRIC	367		Base	TBL load forecast	2003	6.31	6.11	7.53	8.61	8.51	6.56	6.10	5.55	6.48	6.79	7.91	6.27	6.89
266	NESPELEM VALLEY ELECTRIC	367		LS	TBL load forecast	2003	6.39	6.19	7.61	8.69	8.59	6.64	6.10	5.55	6.48	6.79	7.91	6.27	6.93
267	NORTHERN LIGHTS INC	370	PNGC	Base	TBL load forecast	2002	33.07	37.11	44.17	42.73	46.58	38.83	32.75	27.05	23.64	24.23	23.24	21.04	32.87
268	NORTHERN LIGHTS INC	370	PNGC	LS	TBL load forecast	2002	33.66	37.70	44.76	43.32	47.17	39.42	33.28	27.58	24.17	24.76	23.77	21.57	33.43
269	NORTHERN LIGHTS INC	370	PNGC	Base	TBL load forecast	2003	33.37	37.44	44.55	43.10	46.98	39.17	33.51	27.78	24.34	24.94	23.94	21.73	33.40
270	NORTHERN LIGHTS INC	370	PNGC	LS	TBL load forecast	2003	33.90	37.97	45.08	43.63	47.51	39.70	33.51	27.78	24.34	24.94	23.94	21.73	33.67
271	NORTHERN WASCO COUNTY PUD	262		Base	TBL load forecast	2002	37.16	38.00	50.08	57.91	49.22	37.38	39.90	29.93	31.03	32.32	36.83	33.15	39.41
272	NORTHERN WASCO COUNTY PUD	262		LS	TBL load forecast	2002	37.16	38.00	50.08	57.91	49.22	37.38	39.90	29.93	31.03	32.32	36.83	33.15	39.41
273	NORTHERN WASCO COUNTY PUD	262		Base	TBL load forecast	2003	37.31	38.15	50.28	58.14	49.41	37.53	40.06	30.05	31.16	32.45	36.97	33.28	39.57
274	NORTHERN WASCO COUNTY PUD	262		LS	TBL load forecast	2003	37.31	38.15	50.28	58.14	49.41	37.53	40.06	30.05	31.16	32.45	36.97	33.28	39.57
275	OHOP MUTUAL LIGHT COMPANY	372		Base	TBL load forecast	2002	12.51	12.15	16.10	15.82	16.81	12.83	11.25	8.64	5.57	5.33	5.89	5.10	10.67
276	OHOP MUTUAL LIGHT COMPANY	372		LS	TBL load forecast	2002	12.51	12.15	16.10	15.82	16.81	12.83	11.25	8.64	5.57	5.33	5.89	5.10	10.67
277	OHOP MUTUAL LIGHT COMPANY	372		Base	TBL load forecast	2003	12.73	12.37	16.40	16.11	17.11	13.07	11.46	8.80	5.67	5.43	6.00	5.19	10.86
278	OHOP MUTUAL LIGHT COMPANY	372		LS	TBL load forecast	2003	12.73	12.37	16.40	16.11	17.11	13.07	11.46	8.80	5.67	5.43	6.00	5.19	10.86
279	OKANOGAN COUNTY ELECTRIC	373		Base	TBL load forecast	2002	7.20	7.41	9.50	10.86	10.41	7.08	5.67	4.90	4.06	4.57	5.04	4.52	6.77
280	OKANOGAN COUNTY ELECTRIC	373		LS	TBL load forecast	2002	7.20	7.41	9.50	10.86	10.41	7.08	5.67	4.90	4.06	4.57	5.04	4.52	6.77
281	OKANOGAN COUNTY ELECTRIC	373		Base	TBL load forecast	2003	7.21	7.43	9.52	10.89	10.43	7.10	5.68	4.91	4.07	4.58	5.05	4.53	6.78
282	OKANOGAN COUNTY ELECTRIC	373		LS	TBL load forecast	2003	7.21	7.43	9.52	10.89	10.43	7.10	5.68	4.91	4.07	4.58	5.05	4.53	6.78
283	OKANOGAN COUNTY PUD NO 1	266		Base	added 11 MW	2002	65.41	53.35	88.92	101.15	86.71	73.74	60.39	40.17	37.76	20.73	36.26	43.67	59.02
284	OKANOGAN COUNTY PUD NO 1	266		LS	added 11 MW	2002	111.90	95.72	130.41	143.20	128.41	118.90	106.90	87.97	85.80	69.39	87.19	91.37	104.76
285	OKANOGAN COUNTY PUD NO 1	266		Base	added 11 MW	2003	65.41	53.35	88.92	101.15	86.71	73.74	60.39	40.17	37.76	20.73	36.26	43.67	59.02
286	OKANOGAN COUNTY PUD NO 1	266		LS	added 11 MW	2003	111.90	95.72	130.41	143.20	128.41	118.90	106.90	87.97	85.80	69.39	87.19	91.37	104.76
287	ORCAS POWER & LIGHT CO	376		Base	TBL load forecast	2002	31.06	37.17	43.35	49.25	43.03	36.09	29.66	23.24	19.18	18.98	18.81	18.13	30.66
288	ORCAS POWER & LIGHT CO	376		LS	TBL load forecast	2002	31.06	37.17	43.35	49.25	43.03	36.09	29.66	23.24	19.18	18.98	18.81	18.13	30.66
289	ORCAS POWER & LIGHT CO	376		Base	TBL load forecast	2003	31.57	37.78	44.06	50.06	43.74	36.68	30.15	23.63	19.50	19.29	19.12	18.43	31.17
290	ORCAS POWER & LIGHT CO	376		LS	TBL load forecast	2003	31.57	37.78	44.06	50.06	43.74	36.68	30.15	23.63	19.50	19.29	19.12	18.43	31.17
291	OREGON TRAIL COOPERATIVE	371	PNGC	Base	TBL load forecast	2002	90.09	98.15	121.73	112.83	125.16	95.85	85.86	89.40	81.61	92.95	93.26	85.60	97.71
292	OREGON TRAIL COOPERATIVE	371	PNGC	LS	TBL load forecast	2002	90.09	98.15	121.73	112.83	125.16	95.85	85.86	89.40	81.61	92.95	93.26	85.60	97.71
293	OREGON TRAIL COOPERATIVE	371	PNGC	Base	TBL load forecast	2003	90.59	98.69	122.41	113.46	125.86	96.38	86.33	89.89	82.06	93.46	93.77	86.08	98.25
294	OREGON TRAIL COOPERATIVE	371	PNGC	LS	TBL load forecast	2003	90.59	98.69	122.41	113.46	125.86	96.38	86.33	89.89	82.06	93.46	93.77	86.08	98.25
295	PACIFIC COUNTY PUD NO 2	270		Base	TBL load forecast	2002	43.56	43.35	53.21	59.33	65.37	54.76	45.10	35.09	27.24	26.73	24.03	24.12	41.82
296	PACIFIC COUNTY PUD NO 2	270		LS	TBL load forecast	2002	43.56	43.35	53.21	59.33	65.37	54.76	45.10	35.09	27.24	26.73	24.03	24.12	41.82
297	PACIFIC COUNTY PUD NO 2	270		Base	TBL load forecast	2003	44.09	43.88	53.86	60.06	66.17	55.43	45.66	35.52	27.57	27.06	24.33	24.41	42.34
298	PACIFIC COUNTY PUD NO 2	270		LS	TBL load forecast	2003	44.09	43.88	53.86	60.06	66.17	55.43	45.66	35.52	27.57	27.06	24.33	24.41	42.34
299	PARKLAND LIGHT & POWER CO	375		Base	TBL load forecast	2002	18.78	18.98	24.28	25.64	25.09	19.01	17.49	14.28	11.16	11.19	11.11	10.92	17.33
300	PARKLAND LIGHT & POWER CO	375		LS	TBL load forecast	2002	18.78	18.98	24.28	25.64	25.09	19.01	17.49	14.28	11.16	11.19	11.11	10.92	17.33
301	PARKLAND LIGHT & POWER CO	375		Base	TBL load forecast	2003	19.19	19.39	24.80	26.20	25.64	19.42	17.87	14.59	11.40	11.43	11.35	11.16	17.70
302	PARKLAND LIGHT & POWER CO	375		LS	TBL load forecast	2003	19.19	19.39	24.80	26.20	25.64	19.42	17.87	14.59	11.40	11.43	11.35	11.16	17.70
303	PEND OREILLE COUNTY PUD	273		Base	OY99 NWPP Op Pgm	2002	89.97	71.36	72.44	78.59	48.33	29.72	52.63	65.37	88.53	76.92	75.05	54.82	66.98
304	PEND OREILLE COUNTY PUD	273		LS	OY99 NWPP Op Pgm	2002	121.97	103.36	104.44	110.59	80.33	61.72	84.63	97.37	120.53	108.92	107.05	86.82	98.98
305	PEND OREILLE COUNTY PUD	273		Base	OY99 NWPP Op Pgm	2003	90.64	72.04	73.13	78.67	48.59	29.92	53.10	66.20	89.51	77.91	75.12	54.84	67.47
306	PEND OREILLE COUNTY PUD	273		LS	OY99 NWPP Op Pgm	2003	122.64	104.04	105.13	110.67	80.59	61.92	85.10	98.20	121.51	109.91	107.12	86.83	99.47
307	PENINSULA LIGHT COMPANY	374		Base	TBL load forecast	2002	87.35	96.44	121.09	122.67	112.35	97.18	79.19	65.78	50.02	45.61	47.62	49.54	81.24
308	PENINSULA LIGHT COMPANY	374		LS	TBL load forecast	2002	87.35	96.44	121.09	122.67	112.35	97.18	79.19	65.78	50.02	45.61	47.62	49.54	81.24

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
309	PENINSULA LIGHT COMPANY	374		Base	TBL load forecast	2003	87.97	97.13	121.95	123.54	113.15	97.87	79.75	66.25	50.37	45.93	47.96	49.89	81.81
310	PENINSULA LIGHT COMPANY	374		LS	TBL load forecast	2003	87.97	97.13	121.95	123.54	113.15	97.87	79.75	66.25	50.37	45.93	47.96	49.89	81.81
311	PLUMMER, CITY OF	167		Base	TBL load forecast	2002	4.32	3.68	4.90	4.85	4.79	3.16	3.42	2.95	2.56	2.57	2.43	2.93	3.55
312	PLUMMER, CITY OF	167		LS	TBL load forecast	2002	4.32	3.68	4.90	4.85	4.79	3.16	3.42	2.95	2.56	2.57	2.43	2.93	3.55
313	PLUMMER, CITY OF	167		Base	TBL load forecast	2003	4.35	3.70	4.93	4.88	4.81	3.17	3.44	2.97	2.58	2.58	2.44	2.94	3.57
314	PLUMMER, CITY OF	167		LS	TBL load forecast	2003	4.35	3.70	4.93	4.88	4.81	3.17	3.44	2.97	2.58	2.58	2.44	2.94	3.57
315	PORT ANGELES, CITY OF	170		Base	TBL load forecast	2002	75.16	83.65	72.29	95.79	106.70	70.56	55.55	50.76	47.17	49.30	54.13	65.20	68.86
316	PORT ANGELES, CITY OF	170		LS	TBL load forecast	2002	76.10	84.59	73.23	96.73	107.64	71.50	56.39	51.60	48.01	50.14	54.97	66.04	69.75
317	PORT ANGELES, CITY OF	170		Base	TBL load forecast	2003	76.03	84.59	73.13	96.85	107.87	71.38	56.96	52.11	48.49	50.64	55.52	66.70	70.02
318	PORT ANGELES, CITY OF	170		LS	TBL load forecast	2003	76.87	85.43	73.97	97.69	108.71	72.22	56.96	52.11	48.49	50.64	55.52	66.70	70.44
319	PORT TOWNSEND PAPER CORP	716		Base	12/98 White Book	2002	13.53	14.49	14.49	14.40	15.60	14.31	14.31	2.40	13.65	14.31	13.00	14.31	13.23
320	PORT TOWNSEND PAPER CORP	716		LS	12/98 White Book	2002	13.53	14.49	14.49	14.40	15.60	14.31	14.31	2.40	13.65	14.31	13.00	14.31	13.23
321	PORT TOWNSEND PAPER CORP	716		Base	12/98 White Book	2003	13.53	14.49	14.49	14.40	15.60	14.31	14.31	2.40	13.65	14.31	13.00	14.31	13.23
322	PORT TOWNSEND PAPER CORP	716		LS	12/98 White Book	2003	13.53	14.49	14.49	14.40	15.60	14.31	14.31	2.40	13.65	14.31	13.00	14.31	13.23
323	RAFT RIVER RURAL ELECTRIC	379	PNGC	Base	TBL load forecast	2002	8.79	6.91	7.79	9.60	7.91	6.86	10.91	30.54	35.14	48.33	37.97	39.11	20.82
324	RAFT RIVER RURAL ELECTRIC	379	PNGC	LS	TBL load forecast	2002	8.79	6.91	7.79	9.60	7.91	6.86	10.91	30.54	35.14	48.33	37.97	39.11	20.82
325	RAFT RIVER RURAL ELECTRIC	379	PNGC	Base	TBL load forecast	2003	8.84	6.95	7.84	9.65	7.96	6.90	10.97	30.71	35.34	48.60	38.18	39.32	20.94
326	RAFT RIVER RURAL ELECTRIC	379	PNGC	LS	TBL load forecast	2003	8.84	6.95	7.84	9.65	7.96	6.90	10.97	30.71	35.34	48.60	38.18	39.32	20.94
327	RAVALLI COUNTY ELECTRIC COOI	380		Base	TBL load forecast	2002	18.61	19.62	24.46	24.62	23.87	20.30	16.55	15.85	13.49	15.46	15.39	12.72	18.41
328	RAVALLI COUNTY ELECTRIC COOI	380		LS	TBL load forecast	2002	18.78	19.79	24.63	24.79	24.04	20.47	16.70	16.00	13.64	15.61	15.54	12.87	18.57
329	RAVALLI COUNTY ELECTRIC COOI	380		Base	TBL load forecast	2003	19.16	20.20	25.17	25.34	24.57	20.89	17.17	16.45	14.03	16.05	15.97	13.23	19.02
330	RAVALLI COUNTY ELECTRIC COOI	380		LS	TBL load forecast	2003	19.31	20.35	25.32	25.49	24.72	21.04	17.17	16.45	14.03	16.05	15.97	13.23	19.09
331	RIVERSIDE ELECTRIC COMPANY	381		Base	TBL load forecast	2002	2.49	2.37	3.62	2.23	1.91	1.74	1.40	1.63	1.91	2.27	1.91	1.64	2.09
332	RIVERSIDE ELECTRIC COMPANY	381		LS	TBL load forecast	2002	2.49	2.37	3.62	2.23	1.91	1.74	1.40	1.63	1.91	2.27	1.91	1.64	2.09
333	RIVERSIDE ELECTRIC COMPANY	381		Base	TBL load forecast	2003	2.50	2.38	3.63	2.24	1.91	1.74	1.41	1.64	1.92	2.28	1.92	1.64	2.10
334	RIVERSIDE ELECTRIC COMPANY	381		LS	TBL load forecast	2003	2.50	2.38	3.63	2.24	1.91	1.74	1.41	1.64	1.92	2.28	1.92	1.64	2.10
335	RUPERT, CITY OF	177		Base	TBL load forecast	2002	25.34	29.55	33.79	28.71	27.30	22.12	24.24	21.71	18.93	21.25	20.66	10.45	23.67
336	RUPERT, CITY OF	177		LS	TBL load forecast	2002	25.34	29.55	33.79	28.71	27.30	22.12	24.24	21.71	18.93	21.25	20.66	10.45	23.67
337	RUPERT, CITY OF	177		Base	TBL load forecast	2003	25.85	30.14	34.46	29.29	27.85	22.57	24.73	22.15	19.31	21.68	21.07	10.65	24.15
338	RUPERT, CITY OF	177		LS	TBL load forecast	2003	25.85	30.14	34.46	29.29	27.85	22.57	24.73	22.15	19.31	21.68	21.07	10.65	24.15
339	SALEM ELECTRIC COOPERATIVE	383		Base	TBL load forecast	2002	61.18	62.77	76.80	73.13	79.33	60.96	54.88	47.57	47.01	51.81	56.52	53.17	60.43
340	SALEM ELECTRIC COOPERATIVE	383		LS	TBL load forecast	2002	61.93	63.52	77.55	73.88	80.08	61.71	55.55	48.24	47.68	52.48	57.19	53.84	61.14
341	SALEM ELECTRIC COOPERATIVE	383		Base	TBL load forecast	2003	61.81	63.41	77.56	73.86	80.12	61.58	56.05	48.67	48.10	52.95	57.70	54.31	61.34
342	SALEM ELECTRIC COOPERATIVE	383		LS	TBL load forecast	2003	62.48	64.08	78.23	74.53	80.79	62.25	56.05	48.67	48.10	52.95	57.70	54.31	61.68
343	SALMON RIVER ELECTRIC COOP	384		Base	TBL load forecast	2002	39.93	38.46	46.43	36.45	23.23	29.51	22.83	19.27	14.29	28.83	43.09	42.67	32.08
344	SALMON RIVER ELECTRIC COOP	384		LS	TBL load forecast	2002	39.93	38.46	46.43	36.45	23.23	29.51	22.83	19.27	14.29	28.83	43.09	42.67	32.08
345	SALMON RIVER ELECTRIC COOP	384		Base	TBL load forecast	2003	40.53	39.04	47.13	37.00	23.58	29.95	23.18	19.56	14.51	29.27	43.74	43.31	32.57
346	SALMON RIVER ELECTRIC COOP	384		LS	TBL load forecast	2003	40.53	39.04	47.13	37.00	23.58	29.95	23.18	19.56	14.51	29.27	43.74	43.31	32.57
347	SKAMANIA COUNTY PUD NO 1	279		Base	TBL load forecast	2002	20.25	17.77	24.79	26.82	28.75	23.43	19.64	15.95	11.90	12.97	12.97	12.67	18.99
348	SKAMANIA COUNTY PUD NO 1	279		LS	TBL load forecast	2002	20.62	18.14	25.16	27.19	29.12	23.80	19.97	16.28	12.23	13.30	13.30	13.00	19.34
349	SKAMANIA COUNTY PUD NO 1	279		Base	TBL load forecast	2003	20.59	18.08	25.20	27.27	29.22	23.82	20.27	16.52	12.42	13.50	13.49	13.20	19.47
350	SKAMANIA COUNTY PUD NO 1	279		LS	TBL load forecast	2003	20.92	18.41	25.53	27.60	29.55	24.15	20.27	16.52	12.42	13.50	13.49	13.20	19.63
351	SODA SPRINGS, CITY OF	181		Base	TBL load forecast	2002	3.24	3.71	4.09	4.05	4.00	3.52	3.08	2.88	2.32	2.50	2.43	2.37	3.18
352	SODA SPRINGS, CITY OF	181		LS	TBL load forecast	2002	3.24	3.71	4.09	4.05	4.00	3.52	3.08	2.88	2.32	2.50	2.43	2.37	3.18

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(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
353	SODA SPRINGS, CITY OF	181		Base	TBL load forecast	2003	3.25	3.71	4.10	4.05	4.00	3.53	3.09	2.88	2.32	2.50	2.44	2.37	3.19
354	SODA SPRINGS, CITY OF	181		LS	TBL load forecast	2003	3.25	3.71	4.10	4.05	4.00	3.53	3.09	2.88	2.32	2.50	2.44	2.37	3.19
355	SOUTH SIDE ELECTRIC LINES	385		Base	TBL load forecast	2002	4.46	4.90	5.81	6.07	6.04	4.71	4.94	8.17	10.84	10.00	7.42	7.27	6.72
356	SOUTH SIDE ELECTRIC LINES	385		LS	TBL load forecast	2002	4.46	4.90	5.81	6.07	6.04	4.71	4.94	8.17	10.84	10.00	7.42	7.27	6.72
357	SOUTH SIDE ELECTRIC LINES	385		Base	TBL load forecast	2003	4.55	4.99	5.92	6.19	6.16	4.80	5.04	8.33	11.05	10.19	7.56	7.41	6.85
358	SOUTH SIDE ELECTRIC LINES	385		LS	TBL load forecast	2003	4.55	4.99	5.92	6.19	6.16	4.80	5.04	8.33	11.05	10.19	7.56	7.41	6.85
359	STEILACOOM, TOWN OF	185		Base	TBL load forecast	2002	7.41	7.15	9.97	9.17	8.82	6.50	5.19	3.73	2.59	2.57	2.64	3.33	5.76
360	STEILACOOM, TOWN OF	185		LS	TBL load forecast	2002	7.41	7.15	9.97	9.17	8.82	6.50	5.19	3.73	2.59	2.57	2.64	3.33	5.76
361	STEILACOOM, TOWN OF	185		Base	TBL load forecast	2003	7.50	7.24	10.10	9.29	8.94	6.58	5.25	3.78	2.63	2.60	2.68	3.37	5.83
362	STEILACOOM, TOWN OF	185		LS	TBL load forecast	2003	7.50	7.24	10.10	9.29	8.94	6.58	5.25	3.78	2.63	2.60	2.68	3.37	5.83
363	SUMAS, CITY OF	186		Base	TBL load forecast	2002	2.35	2.53	2.57	2.64	2.17	2.26	2.09	2.14	2.24	2.12	2.10	2.06	2.27
364	SUMAS, CITY OF	186		LS	TBL load forecast	2002	2.35	2.53	2.57	2.64	2.17	2.26	2.09	2.14	2.24	2.12	2.10	2.06	2.27
365	SUMAS, CITY OF	186		Base	TBL load forecast	2003	2.35	2.54	2.58	2.65	2.17	2.26	2.09	2.14	2.24	2.13	2.11	2.06	2.28
366	SUMAS, CITY OF	186		LS	TBL load forecast	2003	2.35	2.54	2.58	2.65	2.17	2.26	2.09	2.14	2.24	2.13	2.11	2.06	2.28
367	SURPRISE VALLEY ELECTRIC	386		Base	TBL load forecast	2002	19.81	18.09	21.70	18.28	17.89	16.71	14.29	15.32	17.77	26.34	27.22	27.44	20.07
368	SURPRISE VALLEY ELECTRIC	386		LS	TBL load forecast	2002	19.81	18.09	21.70	18.28	17.89	16.71	14.29	15.32	17.77	26.34	27.22	27.44	20.07
369	SURPRISE VALLEY ELECTRIC	386		Base	TBL load forecast	2003	19.91	18.18	21.81	18.37	17.98	16.79	14.37	15.39	17.86	26.47	27.36	27.58	20.17
370	SURPRISE VALLEY ELECTRIC	386		LS	TBL load forecast	2003	19.91	18.18	21.81	18.37	17.98	16.79	14.37	15.39	17.86	26.47	27.36	27.58	20.17
371	TANNER ELECTRIC COOPERATIVE	387		Base	TBL load forecast	2002	10.12	10.79	14.49	13.41	11.17	12.14	9.49	7.19	6.14	6.22	6.49	6.08	9.48
372	TANNER ELECTRIC COOPERATIVE	387		LS	TBL load forecast	2002	10.12	10.79	14.49	13.41	11.17	12.14	9.49	7.19	6.14	6.22	6.49	6.08	9.48
373	TANNER ELECTRIC COOPERATIVE	387		Base	TBL load forecast	2003	10.57	11.27	15.14	14.01	11.67	12.68	9.92	7.51	6.42	6.50	6.78	6.35	9.90
374	TANNER ELECTRIC COOPERATIVE	387		LS	TBL load forecast	2003	10.57	11.27	15.14	14.01	11.67	12.68	9.92	7.51	6.42	6.50	6.78	6.35	9.90
375	TILLAMOOK COUNTY PUD	288		Base	TBL load forecast	2002	64.52	64.37	91.89	89.55	96.99	82.71	66.54	55.36	44.90	44.37	43.95	38.91	65.34
376	TILLAMOOK COUNTY PUD	288		LS	TBL load forecast	2002	65.46	65.31	92.83	90.49	97.93	83.65	67.38	56.20	45.74	45.21	44.79	39.75	66.23
377	TILLAMOOK COUNTY PUD	288		Base	TBL load forecast	2003	65.83	65.68	93.70	91.32	98.90	84.35	68.62	57.24	46.59	46.05	45.62	40.49	67.03
378	TILLAMOOK COUNTY PUD	288		LS	TBL load forecast	2003	66.67	66.52	94.54	92.16	99.74	85.19	68.62	57.24	46.59	46.05	45.62	40.49	67.45
379	TROY, CITY OF	189		Base	TBL load forecast	2002	2.29	2.34	2.77	2.92	2.64	1.99	1.83	1.34	1.10	1.18	1.20	1.45	1.92
380	TROY, CITY OF	189		LS	TBL load forecast	2002	2.29	2.34	2.77	2.92	2.64	1.99	1.83	1.34	1.10	1.18	1.20	1.45	1.92
381	TROY, CITY OF	189		Base	TBL load forecast	2003	2.30	2.35	2.78	2.94	2.65	2.01	1.84	1.35	1.11	1.19	1.21	1.46	1.93
382	TROY, CITY OF	189		LS	TBL load forecast	2003	2.30	2.35	2.78	2.94	2.65	2.01	1.84	1.35	1.11	1.19	1.21	1.46	1.93
383	U.S. AIR FORCE (FAIRCHILD)	430		Base	TBL load forecast	2002	9.50	10.38	10.67	11.22	11.15	10.25	9.95	9.64	10.24	11.05	11.68	10.46	10.52
384	U.S. AIR FORCE (FAIRCHILD)	430		LS	TBL load forecast	2002	9.50	10.38	10.67	11.22	11.15	10.25	9.95	9.64	10.24	11.05	11.68	10.46	10.52
385	U.S. AIR FORCE (FAIRCHILD)	430		Base	TBL load forecast	2003	9.75	10.66	10.95	11.52	11.45	10.52	10.21	9.90	10.51	11.35	12.00	10.74	10.80
386	U.S. AIR FORCE (FAIRCHILD)	430		LS	TBL load forecast	2003	9.75	10.66	10.95	11.52	11.45	10.52	10.21	9.90	10.51	11.35	12.00	10.74	10.80
387	U.S. DEPARTMENT OF NAVY	451		Base	TBL load forecast	2002	31.03	32.11	30.12	38.71	32.56	31.94	32.26	30.58	29.46	29.44	31.35	29.50	31.59
388	U.S. DEPARTMENT OF NAVY	451		LS	TBL load forecast	2002	31.03	32.11	30.12	38.71	32.56	31.94	32.26	30.58	29.46	29.44	31.35	29.50	31.59
389	U.S. DEPARTMENT OF NAVY	451		Base	TBL load forecast	2003	31.48	32.58	30.56	39.27	33.04	32.40	32.74	31.03	29.89	29.87	31.81	29.93	32.05
390	U.S. DEPARTMENT OF NAVY	451		LS	TBL load forecast	2003	31.48	32.58	30.56	39.27	33.04	32.40	32.74	31.03	29.89	29.87	31.81	29.93	32.05
391	U.S. DEPARTMENT OF NAVY	490		Base	TBL load forecast	2002	24.65	25.68	25.51	27.46	30.00	26.23	25.27	23.26	22.46	21.89	17.39	20.67	24.21
392	U.S. DEPARTMENT OF NAVY	490		LS	TBL load forecast	2002	24.65	25.68	25.51	27.46	30.00	26.23	25.27	23.26	22.46	21.89	17.39	20.67	24.21
393	U.S. DEPARTMENT OF NAVY	490		Base	TBL load forecast	2003	24.94	25.99	25.81	27.78	30.35	26.54	25.56	23.53	22.73	22.14	17.60	20.91	24.49
394	U.S. DEPARTMENT OF NAVY	490		LS	TBL load forecast	2003	24.94	25.99	25.81	27.78	30.35	26.54	25.56	23.53	22.73	22.14	17.60	20.91	24.49
395	U.S. DEPARTMENT OF NAVY	491		Base	TBL load forecast	2002	1.56	1.53	1.79	1.61	1.66	1.47	1.70	1.57	1.51	1.60	1.48	1.59	1.59
396	U.S. DEPARTMENT OF NAVY	491		LS	TBL load forecast	2002	1.56	1.53	1.79	1.61	1.66	1.47	1.70	1.57	1.51	1.60	1.48	1.59	1.59

Appendix B
NT Base and Load Shaping Sales
FY 2002 and FY 2003
(cp MW)

	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
397	U.S. DEPARTMENT OF NAVY	491		Base	TBL load forecast	2003	1.60	1.57	1.84	1.65	1.70	1.50	1.74	1.61	1.55	1.64	1.51	1.63	1.63
398	U.S. DEPARTMENT OF NAVY	491		LS	TBL load forecast	2003	1.60	1.57	1.84	1.65	1.70	1.50	1.74	1.61	1.55	1.64	1.51	1.63	1.63
399	UMATILLA ELECTRIC COOPERA	388	PNGC	Base	TBL load forecast	2002	91.92	104.63	126.72	103.17	79.91	89.07	80.76	130.01	140.58	151.93	162.09	122.50	115.27
400	UMATILLA ELECTRIC COOPERA	388	PNGC	LS	TBL load forecast	2002	91.92	104.63	126.72	103.17	79.91	89.07	80.76	130.01	140.58	151.93	162.09	122.50	115.27
401	UMATILLA ELECTRIC COOPERA	388	PNGC	Base	TBL load forecast	2003	93.88	106.86	129.42	105.37	81.62	90.97	82.48	132.79	143.58	155.17	165.55	125.11	117.73
402	UMATILLA ELECTRIC COOPERA	388	PNGC	LS	TBL load forecast	2003	93.88	106.86	129.42	105.37	81.62	90.97	82.48	132.79	143.58	155.17	165.55	125.11	117.73
403	UNITED ELECTRIC COOP	311		Base	TBL load forecast	2002	24.45	22.67	31.49	32.21	31.08	24.29	21.03	22.23	27.17	33.60	28.45	27.70	27.20
404	UNITED ELECTRIC COOP	311		LS	TBL load forecast	2002	24.45	22.67	31.49	32.21	31.08	24.29	21.03	22.23	27.17	33.60	28.45	27.70	27.20
405	UNITED ELECTRIC COOP	311		Base	TBL load forecast	2003	25.36	23.52	32.66	33.41	32.23	25.20	21.81	23.06	28.18	34.85	29.51	28.73	28.21
406	UNITED ELECTRIC COOP	311		LS	TBL load forecast	2003	25.36	23.52	32.66	33.41	32.23	25.20	21.81	23.06	28.18	34.85	29.51	28.73	28.21
407	US BUREAU OF MINES	410		Base	TBL load forecast	2002	0.72	0.62	0.91	1.14	1.13	0.76	0.66	0.52	0.31	0.36	0.34	0.29	0.65
408	US BUREAU OF MINES	410		LS	TBL load forecast	2002	0.72	0.62	0.91	1.14	1.13	0.76	0.66	0.52	0.31	0.36	0.34	0.29	0.65
409	US BUREAU OF MINES	410		Base	TBL load forecast	2003	0.73	0.63	0.92	1.16	1.14	0.76	0.66	0.53	0.31	0.37	0.34	0.30	0.65
410	US BUREAU OF MINES	410		LS	TBL load forecast	2003	0.73	0.63	0.92	1.16	1.14	0.76	0.66	0.53	0.31	0.37	0.34	0.30	0.65
411	US DEPT OF ENERGY (300 AREA)	405		Base	TBL load forecast	2002	35.36	34.95	42.19	44.42	42.83	37.58	35.54	31.15	30.34	36.36	39.10	36.59	37.20
412	US DEPT OF ENERGY (300 AREA)	405		LS	TBL load forecast	2002	35.36	34.95	42.19	44.42	42.83	37.58	35.54	31.15	30.34	36.36	39.10	36.59	37.20
413	US DEPT OF ENERGY (300 AREA)	405		Base	TBL load forecast	2003	35.54	35.13	42.40	44.65	43.04	37.77	35.72	31.31	30.49	36.55	39.29	36.78	37.39
414	US DEPT OF ENERGY (300 AREA)	405		LS	TBL load forecast	2003	35.54	35.13	42.40	44.65	43.04	37.77	35.72	31.31	30.49	36.55	39.29	36.78	37.39
415	USBIA-MISSION VALLEY POWER	483		Base	TBL load forecast	2002	40.71	47.62	57.41	59.02	59.11	48.52	42.64	40.59	34.38	38.23	40.42	36.61	45.44
416	USBIA-MISSION VALLEY POWER	483		LS	TBL load forecast	2002	40.71	47.62	57.41	59.02	59.11	48.52	42.64	40.59	34.38	38.23	40.42	36.61	45.44
417	USBIA-MISSION VALLEY POWER	483		Base	TBL load forecast	2003	41.20	48.19	58.10	59.73	59.82	49.10	43.16	41.07	34.79	38.69	40.91	37.05	45.98
418	USBIA-MISSION VALLEY POWER	483		LS	TBL load forecast	2003	41.20	48.19	58.10	59.73	59.82	49.10	43.16	41.07	34.79	38.69	40.91	37.05	45.98
419	USBR, YAKIMA PROJECT (ROZA)	472		Base	TBL load forecast	2002	6.70	1.22	5.92	7.80	14.39	15.42	12.89	12.96	9.82	9.41	8.59	11.63	9.73
420	USBR, YAKIMA PROJECT (ROZA)	472		LS	TBL load forecast	2002	6.70	1.22	5.92	7.80	14.39	15.42	12.89	12.96	9.82	9.41	8.59	11.63	9.73
421	USBR, YAKIMA PROJECT (ROZA)	472		Base	TBL load forecast	2003	6.79	1.24	6.00	7.91	14.59	15.63	13.06	13.13	9.95	9.54	8.71	11.78	9.86
422	USBR, YAKIMA PROJECT (ROZA)	472		LS	TBL load forecast	2003	6.79	1.24	6.00	7.91	14.59	15.63	13.06	13.13	9.95	9.54	8.71	11.78	9.86
423	VERA IRRIGATION DISTRICT	191		Base	TBL load forecast	2002	32.65	36.71	41.45	45.50	45.08	35.89	29.94	29.59	22.74	24.58	25.41	24.10	32.80
424	VERA IRRIGATION DISTRICT	191		LS	TBL load forecast	2002	33.03	37.09	41.83	45.88	45.46	36.27	30.28	29.93	23.08	24.92	25.75	24.44	33.16
425	VERA IRRIGATION DISTRICT	191		Base	TBL load forecast	2003	32.87	36.95	41.72	45.79	45.37	36.13	30.44	30.10	23.20	25.06	25.89	24.57	33.17
426	VERA IRRIGATION DISTRICT	191		LS	TBL load forecast	2003	33.21	37.29	42.06	46.13	45.71	36.47	30.44	30.10	23.20	25.06	25.89	24.57	33.34
427	VIGILANTE ELECTRIC COOPER	390		Base	TBL load forecast	2002	17.97	19.32	24.98	19.44	19.44	16.19	12.38	16.98	21.86	27.54	24.46	17.21	19.81
428	VIGILANTE ELECTRIC COOPER	390		LS	TBL load forecast	2002	17.97	19.32	24.98	19.44	19.44	16.19	12.38	16.98	21.86	27.54	24.46	17.21	19.81
429	VIGILANTE ELECTRIC COOPER	390		Base	TBL load forecast	2003	18.04	19.39	25.07	19.51	19.51	16.25	12.42	17.05	21.94	27.64	24.55	17.27	19.89
430	VIGILANTE ELECTRIC COOPER	390		LS	TBL load forecast	2003	18.04	19.39	25.07	19.51	19.51	16.25	12.42	17.05	21.94	27.64	24.55	17.27	19.89
431	WAHKIAKUM COUNTY PUD NO 1	293		Base	TBL load forecast	2002	7.04	7.72	9.37	9.86	10.01	8.32	6.75	5.21	4.05	3.87	3.73	3.86	6.65
432	WAHKIAKUM COUNTY PUD NO 1	293		LS	TBL load forecast	2002	7.04	7.72	9.37	9.86	10.01	8.32	6.75	5.21	4.05	3.87	3.73	3.86	6.65
433	WAHKIAKUM COUNTY PUD NO 1	293		Base	TBL load forecast	2003	7.18	7.87	9.55	10.05	10.20	8.48	6.88	5.31	4.13	3.94	3.80	3.93	6.78
434	WAHKIAKUM COUNTY PUD NO 1	293		LS	TBL load forecast	2003	7.18	7.87	9.55	10.05	10.20	8.48	6.88	5.31	4.13	3.94	3.80	3.93	6.78
435	WASCO ELECTRIC COOPERATIVE	394		Base	TBL load forecast	2002	13.33	12.47	16.29	15.88	15.60	13.10	10.93	10.17	9.07	11.37	11.74	10.10	12.50
436	WASCO ELECTRIC COOPERATIVE	394		LS	TBL load forecast	2002	13.33	12.47	16.29	15.88	15.60	13.10	10.93	10.17	9.07	11.37	11.74	10.10	12.50
437	WASCO ELECTRIC COOPERATIVE	394		Base	TBL load forecast	2003	13.43	12.56	16.41	16.00	15.72	13.20	11.02	10.25	9.14	11.46	11.83	10.18	12.60
438	WASCO ELECTRIC COOPERATIVE	394		LS	TBL load forecast	2003	13.43	12.56	16.41	16.00	15.72	13.20	11.02	10.25	9.14	11.46	11.83	10.18	12.60
439	WELLS RURAL ELECTRIC COOP	396		Base	TBL load forecast	2002	85.53	88.37	86.03	88.51	93.39	76.23	81.89	90.84	79.53	77.23	79.76	87.96	84.61
440	WELLS RURAL ELECTRIC COOP	396		LS	TBL load forecast	2002	85.53	88.37	86.03	88.51	93.39	76.23	81.89	90.84	79.53	77.23	79.76	87.96	84.61

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	Customer Name	No.	Agent	Rate	Source	FYear	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
441	WELLS RURAL ELECTRIC COOP	396		Base	TBL load forecast	2003	85.96	88.81	86.46	88.95	93.86	76.62	82.30	91.30	79.93	77.62	80.16	88.40	85.03
442	WELLS RURAL ELECTRIC COOP	396		LS	TBL load forecast	2003	85.96	88.81	86.46	88.95	93.86	76.62	82.30	91.30	79.93	77.62	80.16	88.40	85.03
443	WEST OREGON ELECTRIC COOP	397		Base	TBL load forecast	2002	13.91	18.35	18.97	19.69	17.95	13.82	14.40	10.58	8.46	9.53	9.42	10.04	13.76
444	WEST OREGON ELECTRIC COOP	397		LS	TBL load forecast	2002	13.91	18.35	18.97	19.69	17.95	13.82	14.40	10.58	8.46	9.53	9.42	10.04	13.76
445	WEST OREGON ELECTRIC COOP	397		Base	TBL load forecast	2003	14.22	18.76	19.39	20.12	18.35	14.13	14.72	10.82	8.65	9.74	9.63	10.27	14.07
446	WEST OREGON ELECTRIC COOP	397		LS	TBL load forecast	2003	14.22	18.76	19.39	20.12	18.35	14.13	14.72	10.82	8.65	9.74	9.63	10.27	14.07
447	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
448	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
449	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90
450	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90
451	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
452	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
453	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90
454	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90
455	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
456	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2002	23.26	20.81	23.92	31.56	25.31	16.60	22.87	23.79	23.21	23.22	24.99	24.43	23.66
457	WHATCOM COUNTY PUD NO 1	298		Base	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90
458	WHATCOM COUNTY PUD NO 1	298		LS	TBL load forecast	2003	23.50	21.02	24.16	31.88	25.56	16.77	23.10	24.03	23.44	23.46	25.25	24.68	23.90

APPENDIX C

Utility Delivery Billing Determinants

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
1	Ashland, City Of	103	968	Mountain Avenue	12.5	8.76
2	Bandon, City Of	104	44	Bandon	12.5	6.34
3			386	Langlois	12.5	0.56
4			992	Two Mile Road	12.5	2.83
5						9.73
6	Benton REA	303	71	Blackrock	115.0	0.24
7			284	Grandview 12.5	12.5	3.59
8			418	Mabton	12.5	2.44
9			884	Rattle Snake	115.0	1.47
10			769	White Swan	12.5	3.81
11						11.55
12	Big Bend Electric	306	46	Baxter	13.8	5.22
13			175	Delight	24.9	0.83
14			195	Eagle Lake	13.8	6.13
15			216	Eltopia	13.8	3.30
16			272	Glade	13.8	5.03
17			310	Hatton	24.9	6.02
18			442	Mesa	13.8	6.09
19			562	Ralston	24.9	0.54
20			582	Ringold	13.8	3.55
21			586	Ritzville	24.9	4.01
22			621	Schrag	24.9	3.79
23			624	Scooteney 13.8 kV	13.8	2.80
24						47.33
25	Blachly-Lane Electric	309	754	Walton	12.5	0.96
26	Bureau of Mines	410	15	Albany	12.5	0.65
27	Cascade Locks, City Of	115	901	Acton	13.8	0.54
28			115	Cascade Locks	13.8	2.64
29						3.18
30	Central Electric Cooperative	312	298	Hampton	25.0	1.12
31	Central Lincoln PUD	207	263	Gardiner	13.8	22.08
32			425	Mapleton	12.5	3.89
33			572	Reedsport	12.5	10.33
34						36.30
35	Cheney, City Of	123	129	Cheney	13.8	12.55
36			253	Four Lakes	13.8	6.63
37						19.18
38	Clark PUD	216	103	Camas 12.5	12.5	27.32
39			107	Carborundum 12.5	12.5	22.69
40			127	Chelatchie 12.5	12.5	9.08
41			1351	Fishers Road 12.5	12.5	21.09
42			448	Mill Plain 12.5	12.5	18.54
43			1341	Van Ship 12.5	12.5	19.31
44						118.02
45	Clatskanie	219	134	Clatskanie	12.5	8.89
46	Clearwater Power	315	547	Potlatch	24.9	4.59
47	Columbia Basin Electric	318	342	Boardman (Ione)	12.5	14.16

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
48	Columbia Power	321	1334	Spray	24.9	0.70
49	Columbia REA	324	98	Burbank	13.8	2.28
50			661	Stateline	69.0	2.65
51			672	Sun Harbor	24.9	2.69
52			751	Walla Walla	12.5	4.39
53						12.02
54	Columbia River PUD	221	829	St. Helens 12.5	12.5	4.86
55	Consumers Power Inc.	327	100	Burnt Wood	25.0	1.65
56			260	Froman	115.0	5.87
57			460	Monmouth	12.5	1.91
58			489	North Butte	12.5	1.36
59			721	Tumble Creek	24.9	2.69
60						13.48
61	Coos-Curry Electric	330	43	Bandon	12.5	1.91
62			387	Langlois	12.5	1.44
63			492	Norway	12.5	2.36
64			543	Port Orford	12.5	4.16
65						9.87
66	Coulee Dam, City Of	125	158	Coulee Dam	12.0	2.99
67	Douglas Electric Coop.	333	187	Drain	12.5	2.73
68			264	Gardiner	13.8	0.50
69			573	Reedsport	12.5	0.66
70						3.90
71	Drain, City Of	128	186	Drain	12.5	4.00
72	Eatonville, Town Of	131	918	Lynch Creek	12.5	4.45
73	Flathead Electric	339	886	Haskell	24.9	2.39
74	Forest Grove, City Of	142	799	Filbert	12.5	10.43
75			247	Forest Grove	12.5	16.92
76			690	Thatcher Junction	12.5	11.51
77						38.86
78	Franklin PUD	233	581	Ringold	13.8	3.37
79	Grant County PUD	238	281	Grand Coulee #1	12.0	3.85
80	Hood River Electric	342	847	Hood River	12.5	1.31
81			520	Parkdale	12.5	6.17
82			782	Woody Guthrie	12.5	8.93
83						16.41
84	Idaho Co. L&P	345	285	East Grangeville	13.8	2.48

Appendix C

Utility Delivery Billing Determinants

12CP Megawatts

	Customer		Delivery Point		
	Name	No.	No. Name	kV	MW
85	Inland Power & Light	348	125 Chambers	13.8	1.61
86			130 Cheney (Inland)	13.8	1.40
87			172 Deer Park	12.5	3.98
88			252 Four Lakes	13.8	3.42
89			262 Gaffney	12.5	0.49
90			300 Hangman	13.8	4.61
91			348 Jerita	12.5	0.73
92			390 Larene	12.5	1.65
93			431 Mayview	13.2	1.67
94			486 Newport	13.8	1.09
95			540 Pomeroy	12.5	0.53
96			583 Riparia	13.8	1.30
97					22.46
98	Lane Electric Cooperative	354	991 Hideaway	12.5	2.13
99	Lincoln Electric (mont.)	357	905 Stillwater	24.9	3.06
100			710 Trego	24.9	11.64
101					14.69
102	Lower Valley Power	360	519 Palisades	12.5	0.00
103			837 Swan Valley	12.5	1.32
104					1.32
105	Mason County PUD No. 1	257	191 Duckabush	12.5	2.81
106	Mason County PUD No. 3	258	545 Potlatch	12.5	2.27
107	Milton, City Of	158	674 Surprise Lake	12.5	8.46
108	Minidoka, City Of	161	451 Minidoka	2.4	0.10
109	Mission Valley Power	483	215 Elmo	12.5	2.06
110	Missoula Electric	364	137 Clinton	12.5	1.38
111			259 Frenchtown	12.5	6.27
112			337 Huson	13.8	3.12
113			683 Tarkio	12.5	0.58
114					11.36
115	Monmouth, City Of	163	459 Monmouth	12.5	10.92
116	Nespelem Valley Electric	367	400 Lone Pine	12.5	1.24
117	Northern Lights	370	79 Bonner's Ferry 13.8	13.8	2.42
118			377 Laclede	13.8	4.07
119			888 Moyie	13.8	0.93
120			891 North Bench	13.8	1.11
121			612 Samuels	13.8	2.52
122			614 Sandpoint	13.8	3.66
123			627 Selle	13.8	4.50
124			716 Troy	13.8	3.37
125			784 Yaak	12.5	0.49
126					23.06
127	Northern Wasco PUD	262	696 The Dalles 12.5	12.5	10.35
128	OHOP Mutual	372	736 Lynch Creek	12.5	3.62
129	Peninsula Light Company	374	903 Narrows	12.5	9.83

Appendix C
Utility Delivery Billing Determinants
12CP Megawatts

	Customer		Delivery Point			
	Name	No.	No.	Name	kV	MW
130	Ravalli Elec. Coop.	380	156	Corvallis	12.5	5.02
131			286	Grantsdale	12.5	1.81
132			666	Stevensville	12.5	3.99
133			740	Victor	12.5	3.25
134						14.08
135	Skamania County PUD	279	106	Cape Horn	12.5	3.29
136			113	Carson	12.5	7.33
137			80	North Bonneville	12.5	1.88
138			870	Stevenson	12.5	4.30
139			727	Underwood	12.5	2.68
140						19.49
141	Steilacoom, Town Of	185	663	Steilacoom	12.5	5.79
142	Surprise Valley	386	169	Davis Creek	12.5	0.49
143	Tillamook PUD	288	48	Beaver	12.5	2.36
144			265	Garibaldi	24.9	7.29
145			320	Hebo	20.8	0.84
146			457	Mohler	24.9	8.11
147			701	Tillamook 12.5	12.5	15.91
148			703	Tillamook 24.9	24.9	19.54
149						54.03
150	Troy, City Of	189	919	Troy	13.8	1.93
151	Wahkiakum County PUD	293	116	Cathlamet	12.5	5.67
152			676	Grays River	12.5	1.04
153						6.71
154	Wasco Electric	394	534	Pine Hollow	12.5	0.67
155			693	The Dalles	12.5	2.26
156			723	Tygh Valley	12.5	4.37
157						7.31
158	West Oregon Electric	397	478	Necanicum	12.5	0.49
159	Delivery Billing Determinant					645

APPENDIX D

TBL Load Forecasting Methodology and Scope

Appendix D

TBL Load Forecasting Methodology and Scope

Load Analysis Methodology for Non-Generating Utilities

TBL's Load Forecasting Group prepared load projections for the 120 customers identified in Table D1. Also shown in Table D1 are those entities excluded from this analysis, which are the Investor Owned Utilities (IOUs), Public Generating Utilities, and Direct Service Industries.

Load forecasts are determined by first extracting monthly metered raw load data from the Billing Information System (BIS) for the period January 1994 through December 1998. Annual growth rates for the utility's system requirements are then calculated for the period 1994 through 1998. This system-specific historical compound average annual growth rate (AARG) is then used to "grow" the system requirements (MWh) for the period (1999 – 2003). This assumes that near term future growth will not significantly depart from recent historical growth.

The historical data provides the basis for reviewing the varied loading patterns within a utility's distribution network. This gives the means by which the Point of Delivery (POD) shares of a utility's system requirements and monthly load shapes are determined. The derived values are then used to allocate projected monthly (MWh) loads by POD. It is assumed that monthly POD load profiles for a customer's system will emulate recent history.

Load factors (both historical POD and month specific) were used to estimate the non-coincidental demands in the forecast period. Load factor is defined as the monthly energy divided by (the maximum peak load * hours). Historical diversity factors are calculated for both coincident and "Total Transmission System Load" (TTSL) demands. For purposes here, "TTSL" demand is the demand at a POD at the time of the peak TTSL. Coincident demand is the POD's contribution to the customer's peak demand. The formulas used are:

1) Coincident MW divided by Non-Coincident MW = Coincident diversity factor
2) TTSL MW divided by Non-Coincident MW = TTSL diversity factor

These diversity factors are then applied to the estimated non-coincident demand to obtain projected coincident and TTSL demands.

Appendix D, Table 1

Scope of Forecast: Included and Excluded Utilities

	Name	No.
	Customers included in forecast	
1	Albany Research Center *Bureau of Mines)	410
2	Albion, City of	102
3	Alder Mutual Light Company	301
4	Ashland, City of	103
5	Asotin PUD	201
6	Bandon, City of	104
7	Benton PUD	203
8	Benton REA	303
9	Big Bend Electric Coop.	306
10	Blachly-Lane County Coop. Electric	309
11	Blaine, City of	106
12	Bonners Ferry Electric, City of	107
13	Burley, City of	109
14	Canby Utility Board	111
15	Cascade Locks, City of	115
16	Central Electric Coop.	312
17	Central Lincoln PUD	207
18	Centralia, City of	119
19	Cheney, City of	123
20	Chewelah, City of	124
21	Clallam County PUD No. 1	213
22	Clatskanie PUD	219
23	Clearwater Power Company	315
24	Columbia Power Coop.	321
25	Columbia REA	324
26	Columbia River PUD	221
27	Columiba Basin Electric Coop.	318
28	Consolidated Irr. Dist #19	192
29	Consumers Power Inc.	327
30	Coos-Currry Electric Coop.	330
31	Coulee Dam Light Dept. City of	125
32	Declo, City of	127
33	Douglas Electric Coop. Inc.	333
34	Drain, City of	128
35	East End Mutual Electric	335
36	Eatonville, Town of	131
37	Ellensburg, City of	133
38	Elmhurst Mutual Power & Light Co.	334
39	Emerald PUD	229
40	Fairchild Air Base	430
41	Fall River Electric Coop.	337
42	Farmers Electric Co.	338
43	Ferry County PUD No. 1	230
44	Fircrest, City of	140
45	Flathead Electric Coop. Inc.	339
46	Forest Grove, City of	142
47	Franklin County PUD	233

Appendix D, Table 1

Scope of Forecast: Included and Excluded Utilities

	Name	No.
48	Glacier Electric Coop. Inc.	340
49	Harney Electric Coop.	341
50	Heyburn, City of	150
51	Hood River Electric Coop.	342
52	Idaho County Light and Power Coop.	345
53	Idaho Falls, City of	152
54	Inland Power & Light Company	348
55	Kittitas County PUD No. 1	246
56	Klickitat County PUD	250
57	Kootenai Electric Coop.	351
58	Lakeview Light & Power Company	353
59	Lane Electric Coop. Inc.	354
60	Lewis County PUD No. 1	253
61	Lincoln Electric Coop. (Mont.)	357
62	Lost River Electric Coop.	359
63	Lower Valley Power and Light	360
64	Mason County PUD No. 1	257
65	Mason County PUD No. 3	258
66	McCleary, City of	154
67	McMinnville, City of	155
68	Midstate Electric Coop.	361
69	Milton, City of	158
70	Milton-Freewater, City of	159
71	Minidoka, City of	161
72	Mission Valley Power	483
73	Missoula Electric Coop. Inc.	364
74	Modern Electric Water Company	366
75	Monmouth, City of	163
76	Nespelem Valley Coop.	367
77	Northern Lights Inc.	370
78	Northern Wasco County PUD	262
79	OHOP Mutual Light Company	372
80	Okanogan County Electric Coop.	373
81	Orcas Power & Light Company	376
82	Oregon Trail Consumers Coop.	371
83	Pacific County PUD No. 2	270
84	Parkland Light & Water Company	375
85	Peninsula Light Company Inc.	374
86	Plummer, City of	167
87	Port Angeles, City of	170
88	Raft River Elec. Coop.	379
89	Ravalli County Electric Coop.	380
90	Richland, City of	175
91	Riverside Electric Co.	381
92	Rupert, City of	177
93	Salem Electric	383
94	Salmon River Coop.	384
95	Skamania County PUD	279
96	Soda Spring, City of	181

Appendix D, Table 1

Scope of Forecast: Included and Excluded Utilities

	Name	No.
97	South Side Elec. Lines	385
98	Springfield Utility Board	184
99	Steilacoom, Town of	185
100	Sumas, City of	186
101	Surprise Valley Elec.	386
102	Tanner Electric Coop.	387
103	Tillamook PUD	288
104	Troy, City of	189
105	Umatilla Electric Coop.	388
106	United Electric Cooperative	311
107	US DOE Richland	405
108	US Navy - Bangor	490
109	US Navy - Jim Creek	491
110	US Navy - Puget Sound Naval Ship.	451
111	Vera Water and Power	191
112	Vigilante Electric Coop.	390
113	Wahkiakum County PUD	293
114	Wapato	482
115	Wasco Electric Coop.	394
116	Wells Rural Electric	396
117	West Oregon Electric Coop.	397
118	Whatcom County PUD No. 1	298
119	WPPSS (Energy Northwest)	195
120	Yakima Project (Roza)	472

Appendix D, Table 1

Scope of Forecast: Included and Excluded Utilities

	Name	No.
	Customers Excluded from Forecast	
121	ACPC, Inc.	701
122	Alcoa	605
123	Chelan County PUD No. 1	210
124	Clark Public Utilities	216
125	Columbia Falls Aluminum	615
126	Cowlitz County PUD	222
127	Douglas County PUD No. 1	226
128	Elf Atochem	702
129	Eugene Water and Electric Board	137
130	Georgia Pacific West Inc.	722
131	Glenbrook Nickel Joint Venture	725
132	Goldendale Aluminum (Col. Alum.)	614
133	Grant County PUD No. 2	238
134	Grays Harbor County PUD	241
135	Idaho Power Company	530
136	Intalco	640
137	Kaiser Aluminum	651
138	NW Aluminum Co.	635
139	Okanogan County PUD No. 1	266
140	Oregon Metallurigical	743
141	Oregon Steel Mill (Gilmore Steel)	785
142	Pacific Power and Light	560
143	Pend Oreille County PUD No. 1	273
144	Port Townsend Paper	716
145	Portland General Electric	575
146	Puget Sound Energy	580
147	Reynolds Metals Company	675
148	Seattle City Light	108
149	Snohomish County PUD No. 1	283
150	Tacoma Public Utilities	188
151	Vanalco	695
152	Washington Water Power	590

Appendix D, Table 2

Other Load-related Information

CUSTOMER	NO.	TYPE OF DATA (A)	SOURCE (B)	OCT (C)	NOV (D)	DEC (E)	JAN (F)	FEB (G)	MAR (H)	APR (I)	MAY (J)	JUN (K)	JUL (L)	AUG (M)	SEP (N)
CHELAN	210	System load	NWPP 12/98	243.7	281.9	328.8	347.1	348.4	272.4	217.2	182.9	164.5	174.6	163.1	170.0
CHELAN	210	Firm resource	NWPP 12/98	373.9	372.0	370.4	369.9	371.0	370.8	370.3	361.8	357.3	379.1	374.6	374.4
CHELAN	210	Firm BPA	NWPP 12/98	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
CHELAN	210	System load coincidence factor	History	0.928	0.762	0.773	0.644	0.985	0.652	0.843	0.704	0.975	0.685	0.863	0.916
CHELAN	210	Coincidence factor for BPA firm	History	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CHELAN	210	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
GRANT	238	System load	NWPP 12/98	382.5	408.3	445.5	495.2	468.7	393.2	426.1	452.5	461.3	497.9	446.7	435.1
GRANT	238	Firm resource	NWPP 12/98	659.5	659.5	659.5	659.5	659.5	659.5	659.5	659.5	659.5	659.5	659.5	659.5
GRANT	238	Firm BPA	NWPP 12/98	3.6	6.4	7.7	42.2	49.7	5.4	12.5	36.0	34.7	3.2	2.5	2.2
GRANT	238	System load coincidence factor	History	1.000	0.471	0.815	1.000	0.354	0.960	0.767	0.650	0.842	0.849	0.941	1.000
GRANT	238	Coincidence factor for BPA firm	History	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
GRANT	238	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
DOUGLAS	226	System load	NWPP 12/98	126.3	151.5	167.6	181.9	166.5	148.9	124.9	111.6	106.8	112.1	112.1	104.4
DOUGLAS	226	Firm resource	NWPP 12/98	353.6	353.7	353.7	353.3	353.3	353.2	345.6	345.8	345.8	345.7	351.1	353.6
DOUGLAS	226	Firm BPA	NWPP 12/98	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DOUGLAS	226	System load coincidence factor	History	0.973	0.946	0.807	1.000	0.944	1.000	0.869	0.843	0.949	0.960	0.649	0.841
DOUGLAS	226	Coincidence factor for BPA firm	History	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DOUGLAS	226	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
COWLITZ	222	System load	NWPP 12/98	608.0	641.0	673.0	677.0	661.0	625.0	584.0	553.0	616.0	502.0	506.0	519.0
COWLITZ	222	Firm resource	NWPP 12/98	120.5	120.5	115.7	103.3	98.9	98.9	98.9	112.3	120.5	120.5	120.5	120.5
COWLITZ	222	Firm BPA	NWPP 12/98	430.6	446.1	478.1	482.1	481.1	470.1	435.9	388.2	373.1	372.2	366.7	371.6
COWLITZ	222	Firm resource	NWPP 12/98	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
COWLITZ	222	System load coincidence factor	History	0.808	0.818	0.797	0.819	0.810	0.844	0.826	0.773	0.796	0.828	0.865	0.946
COWLITZ	222	Coincidence factor for BPA firm	History	0.808	0.818	0.797	0.819	0.810	0.844	0.821	0.773	0.796	0.828	0.865	0.946
COWLITZ	222	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
P-O	273	System load	NWPP 12/98	124.7	130.1	139.5	141.3	152.4	138.0	134.0	130.6	120.9	112.4	109.6	112.8
P-O	273	Firm resource	NWPP 12/98	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3
P-O	273	Firm BPA	NWPP 12/98	24.4	29.8	39.2	41.0	52.1	37.6	34.0	30.6	25.0	12.5	9.3	12.5
P-O	273	System load coincidence factor	History	0.962	0.779	0.734	0.781	0.522	0.443	0.621	0.727	0.973	0.943	0.974	0.769
P-O	273	Coincidence factor for BPA firm	History	0.680	0.852	0.933	0.900	0.913	0.870	0.710	0.565	0.200	0.000	0.500	0.769
P-O	273	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
SNOHOMISH	283	System load	NWPP 12/98	1141.0	1334.0	1385.0	1319.0	1424.0	1165.0	1067.0	950.0	813.0	702.0	744.0	858.0
SNOHOMISH	283	Firm resource	NWPP 12/98	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0	211.0
SNOHOMISH	283	Firm BPA	NWPP 12/98	754.0	989.1	1032.1	919.0	1026.1	770.1	667.6	736.6	541.6	377.6	407.0	471.0
SNOHOMISH	283	System load coincidence factor	History	1.000	1.000	1.000	0.956	0.970	0.922	0.965	0.723	0.941	0.900	0.966	0.782
SNOHOMISH	283	Coincidence factor for BPA firm	History	0.818	0.746	0.741	0.866	0.850	0.846	0.779	0.417	0.864	0.755	0.946	0.750
SNOHOMISH	283	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
SCL	180	System load	NWPP 12/98	1598.9	1778.0	1895.8	1893.3	1833.0	1676.2	1579.0	1537.9	1370.4	1395.0	1370.3	1418.1
SCL	180	Firm resource	NWPP 12/98	2052.8	2025.8	2024.7	2023.5	2020.7	2019.5	1862.3	1938.4	2212.7	2097.1	2096.5	2062.5
SCL	180	Firm BPA	NWPP 12/98	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0
SCL	180	System load coincidence factor	History	0.719	0.845	1.000	0.763	0.919	0.831	0.920	0.814	0.972	0.830	0.831	0.801
SCL	180	Coincidence factor for BPA firm	History	0.013	0.000	0.106	0.073	0.139	0.248	0.033	0.000	0.000	0.105	0.126	0.069
SCL	180	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
TCL	188	System load	NWPP 12/98	708.4	836.5	899.8	916.4	925.7	827.3	740.6	646.1	553.1	518.3	510.2	567.2
TCL	188	Firm resource	NWPP 12/98	948.4	878.5	881.2	813.7	711.2	690.9	692.8	759.3	873.9	926.5	979.7	964.5
TCL	188	Firm BPA	NWPP 12/98	86.0	102.0	149.0	153.0	153.0	68.0	26.0	26.0	26.0	68.0	102.0	68.0

Appendix D, Table 2
Other Load-related Information

CUSTOMER	NO.	(A) TYPE OF DATA	(B) SOURCE	(C) OCT	(D) NOV	(E) DEC	(F) JAN	(G) FEB	(H) MAR	(I) APR	(J) MAY	(K) JUN	(L) JUL	(M) AUG	(N) SEP
TCL	188	System load coincidence factor	History	0.855	1.000	1.000	1.000	1.000	1.000	1.000	0.862	0.474	0.794	0.936	1.000
TCL	188	Coincidence factor for BPA firm	History	0.429	0.625	0.570	0.602	0.561	0.580	0.497	0.000	0.113	0.418	0.618	0.521
TCL	188	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
EWEB	137	System load	NWPP 12/98	428.0	495.0	534.0	580.0	562.0	497.0	445.0	391.0	352.0	356.0	342.0	348.0
EWEB	137	Firm resource	NWPP 12/98	118.8	113.0	118.9	111.0	122.9	143.1	136.0	137.6	133.3	119.0	112.7	124.6
EWEB	137	Firm BPA	NWPP 12/98	196.4	261.0	299.0	354.9	324.5	239.2	188.7	111.4	83.4	125.3	127.2	93.6
EWEB	137	System load coincidence factor	History	1.000	0.925	0.965	0.915	1.000	0.973	0.931	0.643	0.900	0.862	0.918	0.760
EWEB	137	Coincidence factor for BPA firm	History	0.647	0.456	0.470	0.584	0.566	0.641	0.759	0.033	0.470	0.754	0.878	0.730
EWEB	137	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
CLARK	216	System load	WHITEBOOK 12/98	664.3	750.4	880.3	863.3	859.1	815.7	697.0	627.3	519.0	493.2	496.2	539.6
CLARK	216	Firm resource	WHITEBOOK 12/98	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	205.0	205.0	221.0
CLARK	216	Firm BPA	WHITEBOOK 12/98	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CLARK	216	System load coincidence factor	History	0.940	0.950	0.920	0.940	0.980	0.740	0.720	0.790	0.690	0.710	0.860	0.830
CLARK	216	Coincidence factor for BPA firm	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
CLARK	216	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
CLARK	216	Coincidence factor from contract demands	History	0.000	0.340	0.470	0.920	1.000	1.000	0.890	0.380	0.640	0.820	0.000	0.040
OKN	266	System load	WHITEBOOK 12/98	100.9	121.2	138.2	132.2	127.2	107.9	95.9	91.2	89.9	88.2	85.7	96.6
OKN	266	Firm resource	WHITEBOOK 12/98	64.0	63.0	64.0	64.0	63.0	64.0	63.0	63.0	63.0	63.0	64.0	64.0
OKN	266	Firm BPA	WHITEBOOK 12/98	36.0	51.0	68.0	61.0	57.0	46.0	39.0	21.0	21.0	29.0	27.0	30.0
OKN	266	System load coincidence factor	History	1.000	0.699	0.864	1.000	0.923	1.000	1.000	0.844	0.832	0.662	0.889	0.832
OKN	266	Coincidence factor for BPA firm	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
OKN	266	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
OKN	266	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
GH	241	System load	WHITEBOOK 12/98	207.2	229.6	234.4	243.0	250.6	240.2	225.2	185.2	158.2	152.2	154.7	174.7
GH	241	Firm resource	WHITEBOOK 12/98	54.0	54.0	54.0	54.0	54.0	54.0	27.0	54.0	54.0	54.0	54.0	54.0
GH	241	Firm BPA	WHITEBOOK 12/98	189.0	213.0	218.0	226.0	234.0	223.0	208.0	186.0	163.0	157.0	159.0	179.0
GH	241	System load coincidence factor	History	0.967	1.000	1.000	1.000	1.000	0.912	0.954	0.655	0.944	0.826	0.917	0.695
GH	241	Coincidence factor for BPA firm	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
GH	241	Coincidence factor for internal generation	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
ASOTIN	201	System load	HISTORY	0.080	0.083	0.003	0.002	0.002	0.001	0.082	0.101	0.413	0.719	1.359	1.411
ASOTIN	201	System load coincidence factor	History	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
PORT TOWNSEND PAPER	716	System load	HISTORY	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
PORT TOWNSEND PAPER	716	Firm BPA	HISTORY	15.600	15.600	15.600	15.600	15.600	15.600	15.600	15.600	15.600	15.600	15.600	15.600
PORT TOWNSEND PAPER	716	System load coincidence factor	History	0.867	0.929	0.929	0.923	1.000	0.917	0.917	0.154	0.875	0.917	0.833	0.917
PORT TOWNSEND PAPER	716	Coincidence factor for BPA firm	History	0.867	0.929	0.929	0.923	1.000	0.917	0.917	0.154	0.875	0.917	0.833	0.917
CENTRAL MONTANA COOP	313	System load	treat as NWPP	112.0	129.0	171.0	199.0	150.0	154.0	127.0	114.0	119.0	136.0	140.0	120.0
CENTRAL MONTANA COOP	313	System load coincidence factor	History	0.848	0.879	0.981	0.951	0.974	1.000	0.934	0.815	0.935	0.790	0.783	0.674
CENTRAL MONTANA COOP	313	Firm resource	LETTER AGREEMNT	49.0	69.0	86.0	86.0	85.0	70.0	71.0	48.0	53.0	63.0	66.0	54.0
CENTRAL MONTANA COOP	313	Coincidence factor for internal generation	History	0.848	0.879	0.981	0.951	0.974	1.000	0.934	0.815	0.935	0.799	0.783	0.674

Appendix D, Table 3

Some Determinants of Short-term PSW Sales */

/------------------------------------- Model Statistics -------------------------------------/

(A) Regression Statistics	(B)	(C) Forecast Statistics	
Iterations	1.0	Forecast Observations	0.0
Adjusted Observations	365.0	Mean Abs. Dev. (MAD)	0.0
Deg. of Freedom for Error	352.0	Mean Abs. % Err. (MAPE)	0.00%
R-Squared	0.5	Avg. Forecast Error	0.0
Adjusted R-Squared	0.4	Mean % Error	0.00%
Durbin-Watson Statistic	0.5	Root Mean-Square Error	0.0
Durbin-H Statistic	#NA	Theil's Inequality Coefficient	0.0
AIC	12.1	-- Bias Proportion	0.00%
BIC	12.3	-- Variance Proportion	0.00%
F-Statistic	25.7	-- Covariance Proportion	0.00%
Prob (F-Statistic)	0.0		
Log-Likelihood	-2,714.1		
Model Sum of Squares	56,044,091		
Sum of Squared Errors	64,014,629		
Mean Squared Error	181,860		
Std. Error of Regression	426.5		
Mean Abs. Dev. (MAD)	330.9		
Mean Abs. % Err. (MAPE)	19.62%		
Ljung-Box Statistic	819.2		
Prob (Ljung-Box)	0.0		

/------------------------------------- Coefficients -------------------------------------/

(D) Variable	(E) Coefficient	(F) StdErr	(G) T-Stat	(H) P-Value
Constant term	803.353	555.386	1.446	14.89%
CAPACITY	0.111	0.034	3.301	0.11%
PRICESCMMC	58.412	15.623	3.739	0.02%
TEMPSPSW	15.496	3.117	4.972	0.00%
LTCTRCTINT	**-0.442**	0.222	-1.993	4.70%
OCTNOV	-171.870	217.902	-0.789	43.08%
DECJAN	-433.151	203.559	-2.128	3.40%
FEBMAR	-650.560	186.569	-3.487	0.06%
APRMAY	-710.825	110.246	-6.448	0.00%
JUNJUL	-482.382	81.328	-5.931	0.00%
TUEWEDTHR	233.290	54.616	4.271	0.00%
MONFRI	109.525	53.380	2.052	4.09%
SAT	90.363	77.950	1.159	24.72%

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*/ An analysis of PBL, Oct. 1997 through Sep. 1998. Col(E) Long-term contract coefficient used in study table TRS 5.

APPENDIX E

Network "Choice" Analysis

Appendix E

Network "Choice" Analysis 1/

	Customer	No.	(A) Current	(B) Base	(C) Economic	(D) Agent
			/-----------------Choice		---------------------/	
1	Albion, City of	102	NT	NT	NT	PBL
2	Alder Mutual Light Co.	301	NT	NT	NT	
3	Ashland, City of	103	NTP	NT	NT	
4	Asotin County PUD #1	201	NT	NT	NT	PBL
5	Bandon, City of	104	NTP	NT	NT	
6	Benton Cnty PUD	203	PTP	PTP	NCD	
7	Benton REA	303	NT	NCD	NCD	
8	Big Bend Electric Coop.	306	NT	NT	NT	PBL
9	Blachly-Lane County Coop.	309	NT	NT	NCD	PNGC
10	Blaine	106	NTP	NT	NT	
11	Bonners Ferry (City)	107	NTP			
12	Burley, City of	109	NT	NT	NT	PBL
13	Canby Utility Board	111	NTP	NT	NT	
14	Cascade Locks, City of	115	NTP	NT	NT	
15	Central Elec Coop, Inc.	312	NT	NT	NT	PNGC
16	Central Lincoln PUD	207	NT	NT	NT	
17	Centralia, City of	119	NT	NT	NT	
18	Chelan County PUD #1	210	NTP	STP	NCD	
19	Cheney, City of	123	NT	NT	NT	
20	Chewelah, City of	124	NT	NT	NT	PBL
21	Clallam County PUD #1	213	NT	NT	NT	
22	Clark Public Utilities	216	NT	NT	NT	PPL
23	Clatskanie PUD	219	PTP	PTP	NCD	
24	Clearwater Power Co.	315	NT	NT	NT	
25	Columbia Basin Elec Coop	318	NT	NT	NT	PBL
26	Columbia Power Coop	321	NT	NT	NT	PBL
27	Columbia REA	324	NT	NT	NT	PBL
28	Columbia River PUD	221	NT	NT	NT	
29	Consolidated Irrigation Dist	192	NTP			
30	Consumer's Power, Inc.	327	NT	NT	NT	PNGC
31	Coos-Curry Electric Coop.	330	NT	NT	NCD	PNGC
32	Coulee Dam (City of)	125	NT	NT	NT	PBL
33	Cowlitz County PUD	222	NTP	NCD	NCD	
34	Declo, City of	127	NT	NT	NT	PBL
35	Douglas County PUD # 1	226	PTP	PTP	NCD	
36	Douglas Electric Coop.	333	NT	NT	NT	PNGC
37	Drain, City of	128	NTP	NT	NT	
38	East End Mutual Co.	335	NT	NT	NT	PBL
39	Eatonville, Town of	131	NT	NT	NT	
40	Ellensburg, City of	133	NT	NT	NT	
41	Elmhurst Mutual	334	NT	NT	NT	
42	Emerald PUD	229	NTP	NT	NT	
43	Eugene Water and Electric Board	137	NTP	NCD	NT	
44	Fall River Rural Elec Coop	337	NT	NT	NT	PBL
45	Farmers' Elec Company	338	NT	NT	NT	PBL
46	Ferry County PUD #1	230	NT	NT	NT	PBL
47	Fircrest, City of	140	NT	NT	NT	
48	Flathead Electric Coop., Inc.	339	NTP	NCD	NCD	
49	Forest Grove, City of	142	NTP	NT	NT	
50	Franklin Cnty PUD	233	PTP	NCD	NCD	
51	Glacier Electric Coop., Inc.	340	NT	NT	NT	
52	Grant County PUD #2	238	NTP	PTP	NCD	
53	Grays-Harbor County PUD	241	PTP	PTP	NCD	
54	Harney Elec Coop, Inc.	341	NT	NT	NT	PBL
55	Heyburn, City of	150	NT	NT	NCD	PBL
56	Hood River Elec Coop	342	NT	NT	NT	PBL

Appendix E
Network "Choice" Analysis 1/

	Customer	No.	(A) Current	(B) Base	(C) Economic	(D) Agent
			/-----------------Choice		---------------------/	
57	Idaho County Light & Power	345	NT	NT	NT	
58	Idaho Falls, City of	152	PTP	NCD	NCD	
59	Inland Power & Light Co.	348	NT	NT	NT	
60	Kittitas County PUD #1	246	NTP	NT	NT	
61	Klickitat Cnty	250	PTP	PTP	NT	
62	Kootenai Electric Coop., Inc.	351	NT	NT	NT	
63	Lakeview Light & Power Co.	353	NT	NT	NT	
64	Lane Electric Coop., Inc.	354	NT	NT	NT	PNGC
65	Lewis County PUD #1	253	NT	NT	NT	
66	Lincoln Electric Coop. - MT	357	NT	NT	NT	
67	Lincoln Electric Coop.-WA	358	NT			
68	Lost River Elec Coop, Inc.	359	NT	NT	NCD	PNGC
69	Lower Valley Power & Light	360	NT	NT	NT	
70	Mason County PUD #1	257	NT	NT	NT	
71	Mason County PUD #3	258	NT	NCD	NCD	
72	McCleary, City of	154	NT	NT	NT	
73	McMinnville, City of	155	NT	NT	NT	
74	Midstate Elec Coop, Inc.	361	NT	NT	NT	PBL
75	Milton, City of	158	NT	NT	NT	
76	Milton-Freewater, City of	159	NT	NT	NT	
77	Minidoka, City of	161	NT	NT	NT	PBL
78	Missoula Electric Coop.	364	NT	NT	NT	
79	Modern Electric Co.	366	NT	NT	NT	PBL
80	Monmouth, City of	163	NTP	NT	NT	
81	Nespelem Valley Elec. Coop.	367	NT	NT	NT	PBL
82	Northern Lights, Inc.	370	NT	NT	NCD	PNGC
83	Northern Wasco County PUD	262	NT	NT	NT	
84	Ohop Mutual Light Co.	372	NT	NT	NT	
85	Okanogan County Elec. Coop.	373	NTP	NT	NT	PBL
86	Okanogan County PUD	266	NTP	NT	NT	
87	Orcas Power & Light Co.	376	NT	NT	NT	
88	Oregon Trail Elec Coop	371	NT	NT	NCD	PNGC
89	Pacific County PUD #1	270	NT	NT	NT	
90	Parkland Light & Water Co.	375	NT	NT	NT	
91	Pend Oreille PUD #1	273	NTP	NT	NT	
92	Peninsula Light Co., Inc.	374	NT	NT	NT	
93	Plummer, City of	167	NT	NT	NT	PBL
94	Port Angeles City Light	170	NT	NT	NT	
95	Raft River Rural Elec Coop.	379	NT	NT	NCD	PNGC
96	Ravalli County Electric Coop.	380	NTP	NT	NT	
97	Richland, City of	175	PTP	PTP	NCD	
98	Riverside Elec Company, Ltd.	381	NT	NT	NT	PBL
99	Rupert, City of	177	NT	NT	NT	PBL
100	Rural Elec Company	382	NT			PBL
101	Salem Electric	383	NT	NT	NT	PBL
102	Salmon River Elec	384	NTP	NT	NT	
103	Seattle City Light	180	PTP	NCD	NCD	
104	Skamania County PUD	279	NT	NT	NT	PBL
105	Snohomish County PUD	283	PTP	NCD	NCD	
106	Soda Springs, City of	181	NT	NT	NT	PBL
107	South Side Elec Lines, Inc.	385	NT	NT	NT	PBL
108	Springfield Utility Board	184	PTP	PTP	NCD	
109	Steilacom, Town of	185	NT	NT	NT	
110	Sumas, City of	186	NTP	NT	NT	
111	Surprise Valley Elec. Corp.	386	NT	NT	NT	PBL
112	Tacoma Public Utilities	188	NTP	NCD	NT	

Appendix E

Network "Choice" Analysis 1/

	Customer	No.	(A) Current	(B) Base	(C) Economic	(D) Agent
			/-----------------Choice		---------------------/	
113	Tanner Electric Coop.	387	NTP	NT	NT	
114	Tillamook People's Util. Dist.	288	NT	NT	NT	
115	Troy, City of	189	NTP	NT	NT	
116	Umatilla Elec Coop	388	NT	NT	NCD	PNGC
117	Unity Light & Power	389	NT			PBL
118	Vera Water & Power	191	NT	NT	NT	
119	Vigilante Electric Coop.	390	NT	NT	NT	
120	Wahkiakum County PUD	293	NT	NT	NT	
121	Wasco Elec Coop	394	NT	NT	NT	PBL
122	Wells Rural Elec Company	396	NT	NT	NCD	
123	West Oregon Electric Coop.	397	NTP	NT	NT	
124	Whatcom County PUD #1	298	NT	NT	NT	
125	USBIA-Wapato	498	NT	NT		
126	USBIA- Mission Valley	499	NT	NT		
127	U.S. DEPARTMENT OF NAVY (BANGOR)	490	NTP	NT	NT	
128	US BUREAU OF MINES	410	NTP	NT	NT	
129	WASHINGTON PUBLIC POWER SUPPLY SYST	195	NTP	NT	NT	
130	U.S. AIR FORCE (FAIRCHILD)	430	NT	NT	NCD	PBL
131	US DEPT OF ENERGY (RICHLAND)	404	NTP	NTP		
132	U.S.B.I.A.- Wapato	482	NT	NT	NT	PBL
133	UNITED ELECTRIC COOP	311	NT	NT	NT	PBL
134	ENERYG NW INC., (FEC)	336	NT	NT		
135	US DEPT OF ENERGY (300 AREA)	405	NTP	NT	NT	
136	U.S. DEPARTMENT OF NAVY (PUGET SOUN	451	NTP	NT	NT	
137	USBIA-MISSION VALLEY POWER	483	NT	NT	NT	
138	USBR, YAKIMA PROJECT (ROZA)	472	NT	NT	NT	
139	U.S. DEPARTMENT OF NAVY (JIM CREEK)	491	NTP	NT	NT	
140	NATIONAL ENERGY SYSTEMS COMPANY	817	PTP			
141	VANALCO	695	PTP	PTP		
142	PORT TOWNSEND PAPER CORPORATION	716	NTP	NT	NCD	

1/ Column (A), Current Choice, is the Customer's current service.
Column (B), Base Choice, is the service assumed for the FY 2002/03 rate period.
Column (C), Economic Choice, is the result of the economic analysis.

APPENDIX F

Development of FPT-02 Compensation Factors

Appendix F

Development of FPT-02 Compensation Factors

							Main Grid						Secondary System					POD Rate	Compensation	
			Contr	Demand (MW)							Interc		Interc	Interm		Interm	Priest	Factors	Factors	
Company	Resource	POD Name	No.	POD	Project	Wght	Term1	Miles	Misc	Term2	Term	Txf	Term	Term 1	Miles	Term 2	Rapids	$/kW-yr	$/kW-mo	$/kW-yr
Avista	WNP-3	Westside	92186	32.2	32.2	1.000	1.0	284.4	1.0	1.0	1.0							23.277	1.940	23.277
	Avista System (GTA)	Colbert Tap	91970	15.1	65.3	0.231							1.0	1.0	7.9			1.917		
		Deer Park	91970	11.1	65.3	0.170							1.0	1.0	17.4			2.293		
		Loon Lake	91970	4.4	65.3	0.067							1.0	1.0	22.3			1.090		
		Milan	91970	7.7	65.3	0.118							1.0	1.0	15.4			1.454		
		Noxon	91970	0.1	65.3	0.002									0.2			0.000		
		Priest River	91970	14.9	65.3	0.228								1.0	6.6	1.00		1.882		
		Spirit	91970	4.1	65.3	0.063							1.0	1.0	32.6			1.370		
		Wilbur	91970	7.9	65.3	0.121								1.0	18.0			1.474	0.957	11.481
Cowlitz Co PUD	Priest Rapids	Longview 69	13520	17.0	17.0	1.000	1.0	151.5	1.0	1.0	0.5						-0.2190	14.255	1.188	14.255
	Swift	Longview 69	92043	77.0	77.0	1.000		21.4	1.0	1.0	0.5							5.491	0.458	5.491
	Wanapum	Longview 69	00025	21.0	21.0	1.000	1.0	154.3	1.0	1.0	0.5							14.654	1.221	14.654
Douglas Co PUD	Nilles Corner	Nilles Corner	90066	1.8	1.8	1.000									12.4			6.793	0.566	6.793
	Wells	Columbia 115	92389	4.5	4.5	1.000						1.0	1.0					7.630	0.636	7.630
Okanogan Co PUD	Wells	East Omak 115	90013	0.0	0.0	0.000		72.0	1.0			1.0	1.0					0.000		
	Wells	Tonasket 115	90013	0.0	0.0	0.000		72.0	1.0			1.0		1.0	20.3			0.000	0.000	0.000
PacifiCorp	Centralia	Load Center	09228	638.0	638.0	1.000	1.0	51.0	1.0	1.0	1.0							8.327	0.694	8.327
	Clatsop	Clatsop	14612	5.7	7.0	0.814	1.0	80.4	1.0	1.0		1.0						12.719		
		Astoria	14612	1.3	7.0	0.186							1.0	1.0	57.9			6.624		
		Tillamook	14612	0.0	7.0	0.000							2.0	1.0	67.3	1.00		0.000	1.612	19.343
	Colstrip	Flathead	90168	14.0	140.0	0.100	1.0	136.8	1.0	1.0								1.324		
		Trumbull	90168	14.0	140.0	0.100	1.0	141.5	1.0									1.289		
		Lion Mt	90168	15.0	140.0	0.107	1.0	126.9	1.0									1.281		
		Buckley	90168	70.0	140.0	0.500	1.0	414.9	1.0	1.0								15.528		
		Libby	90168	1.0	140.0	0.007	1.0	172.3	1.0	1.0		1.0		1.0	12.3			0.218		
		Columbia Falls	90168	13.0	140.0	0.093	1.0	172.3	1.0	1.0		1.0		1.0	12.3			2.837		
		Kalispell	90168	13.0	140.0	0.093	1.0	172.3	1.0	1.0		1.0		1.0	12.3			2.837	2.110	25.316
	Hermiston	Alvey	94316	420.0	490.0	0.857	1.0	224.9	1.0									15.631		
		Buckley	94316	70.0	490.0	0.143	1.0	70.0	1.0									1.188	1.402	16.819
	Midpoint-Medford	Roundup	94333	55.0	600.0	0.092	1.0	39.8	1.0	1.0		1.0	1.0					1.344		
		Alvey	94333	145.0	600.0	0.242	1.0	259.9	1.0									4.949		
		Alvey	94333	241.0	600.0	0.402	1.0	224.9	1.0									7.325		
		McNary 69	94333	35.0	600.0	0.058			1.0			1.0	1.0					0.631		
		Santiam	94333	40.0	600.0	0.067	1.0	182.0	1.0	1.0			1.0	1.0				1.339		
		Albany	94333	84.0	600.0	0.140	1.0	206.5	1.0	1.0		1.0	1.0					3.547	1.595	19.134
	Priest Rapids	Midway 230	90100	150.0	235.0	0.638			1.0									2.030		
		Outlook	90100	85.0	235.0	0.362	1.0	22.1	1.0									1.897	0.327	3.927
	PSW(DC)/PPL	Alvey	94280	200.0	200.0	1.000	1.0	27.6	1.0									5.598	0.466	5.598
	Swift	Troutdale	92269	222.0	222.0	1.000		28.9	1.0	1.0	0.5							5.971	0.498	5.971
	Wanapum	Troutdale	26811	269.0	269.0	1.000	1.0	149.0	1.0	1.0	0.5							14.314	1.193	14.314
	Widco	Centralia	92325	17.3	17.3	1.000	1.0	83.5	1.0	1.0	0.5							10.119	0.843	10.119

Appendix F
Development of FPT-02 Compensation Factors

							Main Grid						Secondary System					POD Rate	Compensation	
			Contr	Demand (MW)							Interc		Interc	Interm		Interm	Priest	Factors	Factors	
Company	Resource	POD Name	No.	POD	Project	Wght	Term1	Miles	Misc	Term2	Term	Txf	Term	Term 1	Miles	Term 2	Rapids	$/kW-yr	$/kW-mo	$/kW-yr
Pend Oreille Co PUD	Boundary POI	Usk	92488	32.0	32.0	1.000	1.0	49.0	1.0	0.5	0.5							7.584	0.632	7.584
	Box Canyon	Newport	90006	0.0	0.0	0.000								1.0	2.1			0.000		
		Sacheen	90006	0.0	0.0	0.000		7.8						1.0	13.9	1.00		0.000		
		Metaline Falls	90006	0.0	0.0	0.000												0.000		
		Diamond Lake	90006	0.0	0.0	0.000									8.3	1.00		0.000		
		Usk	90006	0.0	0.0	0.000	1.0		1.0	1.0		1.0		1.0	13.9	1.00		0.000	0.000	0.000
Portland General Electric	Boardman Unit 1	John Day	92260	75.0	75.0	1.000	1.0	28.3	1.0	1.0	1.0							6.873	0.573	6.873
	WNP-3	Keeler	92187	53.7	53.7	1.000	1.0	101.6	1.0	1.0	2.0							12.148	1.012	12.148
Power Resources Coop (PNGC)	Boardman	John Day	94151	50.0	50.0	1.000	1.0	28.3	1.0	1.0								6.293		
		Slatt	94151	0.0	50.0	0.000												0.000	0.524	6.293
Puget Sound Power and Light	WNP-3	Maple Valley	92185	32.2	32.2	1.000	1.0	69.4	1.0	1.0	2.0							10.085	0.840	10.085
Tacoma Public Utilities	Priest Rapids	Cowlitz	13512	71.1	71.1	1.000	1.0	128.5	1.0								-0.2370	11.824	0.985	11.824
	Centralia	Cowlitz	94304	107.0	107.0	1.000		38.1	1.0	1.0								6.270	0.523	6.270
	NFP	John Day	93936	49.3	49.3	1.000	1.0	130.0	1.0									12.157	1.013	12.157
Total FPT.1				2774														13.069		
Total FPT.3				733														8.909		
Total FPT				3507														12.199		

APPENDIX G

DSI UFT Delivery Charge Application

Appendix G
DSI UFT Delivery Charge Application

		(A)	(B)	(C)	(D)	(E)	(F)
		Average ACR	Investment 1/	UFT I&A	O&M	Total 2/	
			($)	($)	($)	($)	
1	FY2002	8.09%	61,490,690	4,976,071	1,180,996	6,157,067	
2	FY2003	8.09%	62,720,504	5,075,593	1,241,101	6,316,694	
3	Average		62,105,597	5,025,832	1,211,049	6,236,881	

	Summary of UFT Sole Use Charges (from Contracts in place as of 2/1/2000)					Projected O&M 4/	
	DSI Facility 3/	Investment	I&A	O&M	Total	2,002.0	2,003.0
		($)	($)	($)	($)	($)	($)
4	ALCOA (Addy)	2,894,264	233,857	44,750	278,607	48,945	51,331
5	ALCOA (Intalco)	5,970,595	485,409	139,968	625,377	153,090	160,552
6	ALCOA (Valhalla)	3,622,454	294,506	91,900	386,406	100,516	105,415
7	Atochem (Penwalt)	2,471,406	199,059	252,075	451,135	252,075	266,903
8	Goldendale Aluminum (Harvalum)	4,244,203	345,054	95,460	440,514	104,409	109,498
9	NW Aluminum (Harvey)	1,790,953	145,604	45,188	190,792	49,424	51,833
10	Reynolds (Longview)	22,196,629	1,793,488	238,174	2,031,662	260,503	273,200
11	Reynolds (Troutdale)	14,753,547	1,192,087	193,860	1,385,947	212,034	222,369
12	**TOTAL**	**57,944,051**	**4,689,063**	**1,101,375**	**5,790,438**	**1,180,996**	**1,241,101**
13	Average ACR		8.09%				

1/ Total investment at 2% annual growth.
2/ Assumes customers with agreements terminating in 2001 will have follow-on agreements
3/ Excludes facilities projected to be sold
4/ O&M projections based upon the projected 3 year average levels as applied to the year the UFT components were last updated

APPENDIX H

Calculation of GTA Replacement Costs

Appendix H
Calculation of GTA Replacement Costs

DETAILED SUMMARY - FY2002

			(A)	(B)	(C)	(D)	(E)
	Transferor	Customer	Load at GTA PODs	Cust Total Load	GTA/TOT	Total Nonfed Power	Nonfed power over GTA PODs
			(MW)	(MW)	A/B	(MW)	C*D
1	Benton Co PUD	Benton REA	21.21	142.99	0.15	44.00	6.53
2	Benton Co PUD	Klickatat PUD	7.44	70.30	0.11	-	-
3	EWEB	Emerald	10.35	109.18	0.09	-	-
4	EWEB	SUB	6.65	208.14	0.03	100.00	3.19
5	Franklin Co PUD	Big Bend Elec	8.82	130.66	0.07	-	-
6	Grant Co PUD	Big Bend Elec	10.04	130.66	0.08	-	-
7	Grant Co PUD	Kittitas PUD # 1	2.32	16.32	0.14	-	-
8	Grays Harbor	McCleary, City of	8.50	8.50	1.00	-	-
9	Idaho Power	Albion	0.89	0.89	1.00	-	-
10	Idaho Power	Burley	25.90	25.90	1.00	-	-
11	Idaho Power	East End	5.31	5.31	1.00	-	-
12	Idaho Power	Farmers	1.18	1.18	1.00	-	-
13	Idaho Power	Harney	19.99	38.19	0.52	-	-
14	Idaho Power	Heyburn, City of	17.86	17.86	1.00	-	-
15	Idaho Power	Minidoka	0.19	0.19	1.00	-	-
16	Idaho Power	OTEC	132.97	132.97	1.00	40.40	40.40
17	Idaho Power	Raft River REC	13.87	63.86	0.22	-	-
18	Idaho Power	Riverside	3.80	3.80	1.00	-	-
19	Idaho Power	Rupert	40.76	40.76	1.00	-	-
20	Idaho Power	Southside	15.26	15.26	1.00	-	-
21	Idaho Power	United	35.17	44.62	0.79	-	-
22	Idaho Power	Wells	87.32	110.69	0.79	-	-
23	Montana Power	Glacier Elec.	33.65	33.65	1.00	0.00	0.00
24	Montana Power	Missoula Elec	37.15	37.15	1.00	0.00	0.00
25	Montana Power	Northern Lights	1.50	53.51	0.03	7.50	0.21
26	Montana Power	Ravalli	30.87	30.87	1.00	0.00	0.00
27	Montana Power	Vigilante	38.72	45.22	0.86	0.00	0.00
28	N Wasco	Wasco Elec.	2.66	21.52	0.12	-	-
29	Okanogan Co PUD	Nespelem	2.34	13.34	0.18	-	-
30	Okanogan Co PUD	Okanogan Coop	12.59	12.59	1.00	-	-
31	Pacificorp	Ashland, City of	37.35	37.35	1.00	-	-
32	Pacificorp	Benton REA	5.39	142.99	0.04	44.00	1.66
33	Pacificorp	Central Elec Coop	43.19	137.75	0.31	27.50	8.62
34	Pacificorp	Columbia Pwr	1.97	6.96	0.28	-	-
35	Pacificorp	Columbia REA	4.12	123.28	0.03	-	-
36	Pacificorp	Cowlitz	4.34	242.53	0.02	196.78	3.52
37	Pacificorp	Douglas Elec Coop	17.21	41.19	0.42	8.00	3.34
38	Pacificorp	Emerald	20.00	109.18	0.18	-	-
39	Pacificorp	Fall River	72.26	72.26	1.00	-	-
40	Pacificorp	Hood River	12.07	23.07	0.52	-	-
41	Pacificorp	Idaho Falls, City of	140.39	140.39	1.00	48.00	48.00
42	Pacificorp	Klickatat PUD	15.90	70.30	0.23	-	-
43	Pacificorp	Lane Electric	4.57	72.20	0.06	10.60	0.67
44	Pacificorp	Lost RiverECoop	20.45	20.45	1.00	13.00	13.00
45	Pacificorp	Lower ValleyP&L	146.71	146.71	1.00	-	-
46	Pacificorp	O Metallurgical	23.11	23.11	1.00	-	-
47	Pacificorp	Salmon RiverECoop	60.39	60.39	1.00	-	-
48	Pacificorp	Soda Springs, City of	4.45	4.45	1.00	-	-
49	Pacificorp	Surprise Valley	27.75	38.79	0.72	-	-

Appendix H
Calculation of GTA Replacement Costs

	Transferor	Customer	(A) Load at GTA PODs (MW)	(B) Cust Total Load (MW)	(C) GTA/TOT A/B	(D) Total Nonfed Power (MW)	(E) Nonfed power over GTA PODs C*D
50	Pacificorp	Tillamook	26.84	115.71	0.23	2.20	0.51
51	Pacificorp	Umatilla Electric	54.88	146.75	0.37	34.00	12.72
52	Pacificorp	Wasco Elec.	3.89	21.52	0.18	-	-
53	Pacificorp	West OR	4.28	25.54	0.17	-	-
54	PGE	Columbia River	22.75	61.73	0.37	-	-
55	PGE	West OR	3.27	25.54	0.13	-	-
56	PSP&L	Blaine, City of	11.26	11.26	1.00	-	-
57	PSP&L	Georgia Pacific	32.00	32.00	1.00	-	-
58	PSP&L	Kittitas PUD # 1	3.07	16.32	0.19	-	-
59	PSP&L	Orcas	54.24	54.24	1.00	-	-
60	PSP&L	Sumas, City of	3.00	3.00	1.00	-	-
61	PSP&L	Tanner	18.49	18.49	1.00	-	-
62	Sierra Pacific	Harney	19.99	38.19	0.52	-	-
63	Sierra Pacific	Wells	79.40	110.69	0.72	-	-
64	South Side Elect.	Declo, City of	0.76	0.76	1.00	-	-
65	Tacoma	Alder Mutual	0.98	0.98	1.00	-	-
66	Tacoma	Eatonville, Town of	6.76	6.76	1.00	-	-
67	Tacoma	Elmhurst	70.64	70.64	1.00	-	-
68	Tacoma	Fircrest, City of	10.30	10.30	1.00	-	-
69	Tacoma	Lakeview	60.14	60.14	1.00	-	-
70	Tacoma	Lewis PUD	3.95	218.35	0.02	-	-
71	Tacoma	Milton, City of	12.70	12.70	1.00	-	-
72	Tacoma	Ohop	6.33	6.33	1.00	-	-
73	Tacoma	Parkland	27.51	27.51	1.00	-	-
74	Tacoma	Peninsula	138.14	138.14	1.00	13.00	13.00
75	Tacoma	Steilacoom, Town of	11.45	11.45	1.00	-	-
76	US DOE	Benton Co PUD	0.33	547.31	0.00	20.00	0.01
77	US DOE	DOE-Richland	29.28	29.28	1.00	-	-
78	Utah P&L	Fall River	72.26	72.26	1.00	-	-
79	Utah P&L	Idaho Falls, City of	140.39	140.39	1.00	48.00	48.00
80	Utah P&L	Lost RiverECoop	20.45	20.45	1.00	13.00	13.00
81	Utah P&L	Lower ValleyP&L				-	-
82	Utah P&L	Salmon RiverECoop	60.39	60.39	1.00	-	-
83	Utah P&L	Soda Springs, City of	4.45	4.45	1.00	-	-
84	WWP	Big Bend Elec	40.68	130.66	0.31	-	-
85	WWP	Cheney, City of	28.42	28.42	1.00	0.00	0.00
86	WWP	Chewelah, City of	5.31	5.31	1.00	-	-
87	WWP	Clearwater	36.26	47.35	0.77	0.11	0.09
88	WWP	Fairchild AF Base	12.53	12.53	1.00	-	-
89	WWP	Idaho Co. L&P	10.88	11.59	0.94	1.00	0.94
90	WWP	Inland P&L	110.09	202.75	0.54	-	-
91	WWP	Kootenai Elec Co	69.85	69.85	1.00	0.00	0.00
92	WWP	Modern Elec	63.40	63.40	1.00	0.00	0.00
93	WWP	Northern Lights	2.88	53.51	0.05	7.50	0.40
94	WWP	Plummer, City of	5.70	5.70	1.00	-	-

Appendix H
Calculation of GTA Replacement Costs

SUMMARY BY TRANSFER AGREEMENT - FY2002

	Transferor	(A) Load at GTA PODs (MW)	(B) Cust Total Loads (MW)	(C) Nonfed power over GTA PODs (MW)	(D) Tariff Rate ($/kwyr)	(E) GTA Repl. Cost ($/yr)
95	Benton Co PUD	28.6	213.3	6.5	0.58	$3,798
96	EWEB	17.0	317.3	3.2	6.18	$19,734
97	Franklin Co PUD	8.8	130.7			
98	Grant Co PUD	12.4	147.0			
99	Grays Harbor	8.5	8.5			
100	Idaho Power	400.5	501.5	40.4	11.67	$471,468
101	Montana Power	141.9	200.4	0.2	43.32	$9,108
102	N Wasco	2.7	21.5			
103	Okanogan Co PUD	14.9	25.9			
104	Pacificorp	751.5	1822.9	92.0	24.30	$2,236,641
105	PGE	26.0	87.3			
106	PSP&L	122.1	135.3			
107	Sierra Pacific	99.4	148.9			
108	South Side Elect.	0.8	0.8			
109	Tacoma	348.9	563.3	13.0	9.06	$117,780
110	US DOE	29.6	576.6	0.0	0.96	$12
111	Utah P&L	297.9	297.9	61.0	24.30	$1,482,267
112	WWP	386.0	631.1	1.4	16.79	$24,005
113	**TOTALS**	**2,697**	**5,830**	**218**		**$4,364,812**

APPENDIX I

Southern Intertie Seasonality Analysis

Appendix I

Southern Intertie Seasonality Analysis

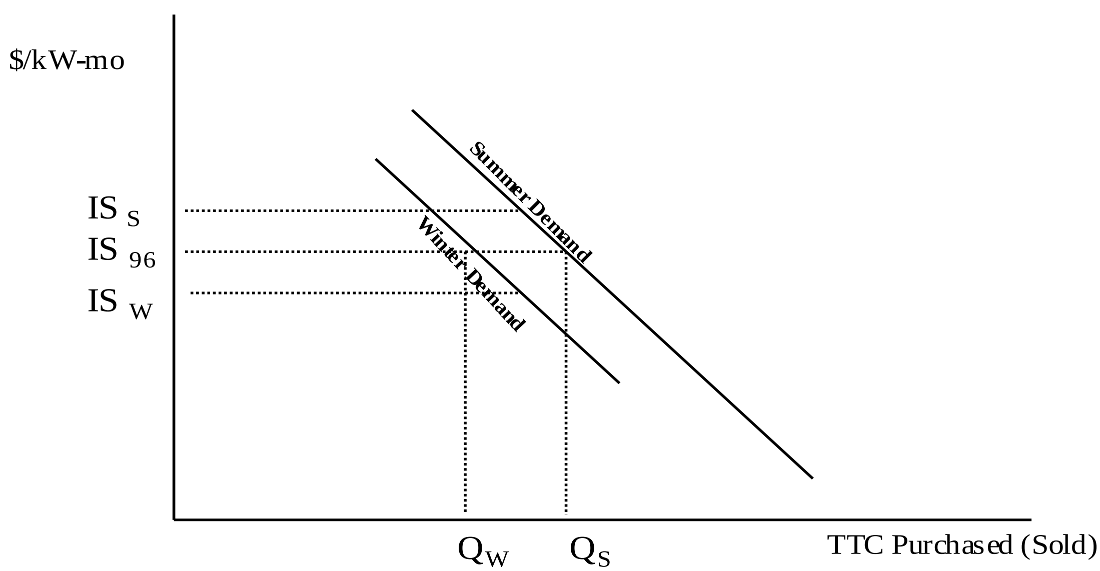
1. <u>Evidence of different demand for Southern Intertie services in Summer vs. Winter</u>.

Table 1 shows the average percentage of Total Transmission Capacity (TTC) sold in each month from May, 1997 through October, 1999. Over the two year period 88% of TTC was sold on average. The average for all summer months was 97% while the average for the winter months was 78%. When looking at two years of data so that the number of months in each season are equal, the average percentage of TTC sold in summer is 101% and 75% in winter.

2. Methodology for Seasonal Differentiation

The observation that demand for service on the Southern Intertie is higher in summer than in winter is depicted in the chart below. With a single price, the quantity demanded in winter is less than in summer. With the seasonal differentiation, the price in winter is 75% of the rate in summer. (The chart is not drawn to scale.)

Illustrative Seasonal Demand For Southern Intertie



Appendix I, Table 1

Total Transmission Capacity Sold by Month

Month	Ave Percent TTC Sold
May-97	78%
Jun-97	86%
Jul-97	98%
Aug-97	101%
Sep-97	
Oct-97	95%
Nov-97	69%
Dec-97	67%
Jan-98	68%
Feb-98	71%
Mar-98	83%
Apr-98	79%
May-98	109%
Jun-98	95%
Jul-98	97%
Aug-98	108%
Sep-98	114%
Oct-98	112%
Nov-98	71%
Dec-98	53%
Jan-99	56%
Feb-99	70%
Mar-99	90%
Apr-99	93%
May-99	104%
Jun-99	107%
Jul-99	101%
Aug-99	101%
Sep-99	99%
Oct-99	114%
Average	**89%**

%TTC sold	Season
88%	Average Oct-98 to Sept-99
75%	Average Oct-98 to Mar-99
101%	Average April-99 to Sept-99
88%	Average Oct-97 to Sept-99
75%	Average Winters 97,98
101%	Average Summers 98,99
98%	Average of All Summer Months
78%	Average of All Winter Months

APPENDIX J

Monthly Transmission Revenue

Appendix J

Monthly Transmission Revenue, ($000)

	FY 2002 Service	Rate	(A) Oct-01	(B) Nov-01	(C) Dec-01	(D) Jan-02	(E) Feb-02	(F) Mar-02	(G) Apr-02	(H) May-02	(I) Jun-02	(J) Jul-02	(K) Aug-02	(L) Sep-02	(M) FY 2002
	General Transmission														
1	Formula Power Transmission............	FPT-02	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	42,787
2	Integration of Resources...............	IR-02	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	54,208
3	Network Transmission, Base............	NT-02	4,384	4,516	5,398	5,483	5,569	4,458	3,933	3,677	3,317	3,528	3,666	3,426	51,354
4	Network Transmission, Load Shaping	NT-02	1,347	1,379	1,632	1,655	1,680	1,362	1,213	1,142	1,040	1,095	1,136	1,068	15,749
5	Network Contract Demand................	NCD-02	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	62,359
6	Point to Point, Long-term Contracts	PTP-02	10,186	10,087	10,404	10,399	10,399	10,399	10,877	10,993	11,025	10,843	10,207	10,207	126,024
7	Point to Point, Daily Block 1..........	PTP-02	433	511	540	829	723	837	923	1,042	1,047	967	929	285	9,066
8	Point to Point, Daily Block 2..........	PTP-02	1,397	976	2,004	1,930	2,144	2,769	2,693	3,042	3,132	3,671	3,185	2,259	29,203
9	Point to Point, Hourly.................	PTP-02	1,510	871	773	2,442	1,650	1,893	747	663	1,294	1,303	1,063	777	14,987
10	**Subtotal General Rates, Network**		**32,536**	**31,619**	**34,031**	**36,018**	**35,444**	**34,997**	**33,665**	**33,838**	**34,136**	**34,685**	**33,465**	**31,302**	**405,737**
11	Southern Intertie, Long-term Contracts	IS-02	3,450	3,364	3,332	3,332	3,332	3,332	4,852	4,986	5,022	5,041	5,041	4,564	49,648
12	Southern Intertie, Daily Block 1.......	IS-02	114	90	56	137	33	167	269	68	173	524	350	460	2,443
13	Southern Intertie, Daily Block 2.......	IS-02	199	148	137	290	369	745	1,350	1,578	1,702	1,640	1,963	1,771	11,893
14	Southern Intertie, Hourly.............	IS-02	1,008	859	451	873	597	379	441	294	620	1,422	993	893	8,829
15	**Subtotal General Rates, Southern Intertie**		**4,771**	**4,462**	**3,976**	**4,632**	**4,330**	**4,624**	**6,912**	**6,927**	**7,517**	**8,626**	**8,347**	**7,689**	**72,812**
16	Montana Intertie......................	IM-02	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Intertie East.........................	IE-02	0	0	0	0	0	0	0	0	0	0	0	0	0
18	DSI Delivery Charge...................	UFT-02	614	614	614	614	614	614	614	614	614	614	614	614	7,368
19	Utility Delivery Charge................	UD	837	832	1,038	1,014	1,042	892	822	743	672	708	713	668	9,981
20	**Subtotal General Transmission Rates**		**38,143**	**36,913**	**39,044**	**41,664**	**40,817**	**40,513**	**41,399**	**41,508**	**42,325**	**44,020**	**42,525**	**39,659**	**488,530**
	Other														
21	Annual Cost Rate......................		115	115	115	115	115	115	115	115	115	115	115	115	1,375
22	Columbia Storage Power Exchange........		24	24	24	24	24	24	21	21	21	21	21	21	268
23	Fiber.................................		1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
24	Fiber Depreciation....................		58	58	58	58	58	58	58	58	58	58	58	58	696
25	Generation Integration................		651	651	651	651	651	651	651	651	651	651	651	651	7,816
26	Irrigation Pumping Power..............		0	0	0	0	0	0	129	258	258	258	258	129	1,288
27	Nonfederal Participation Depreciation		278	278	278	278	278	278	278	278	278	278	278	278	3,335
28	Operations and Maintenance............		59	29	0	0	0	29	29	147	117	117	88	59	675
29	Personal Communications Wireless.......		339	339	339	339	339	339	339	339	339	339	339	339	4,070
30	Power Factor Penalty Charge...........		428	440	519	526	535	435	387	357	330	346	359	336	5,000
31	Remedial Action Scheme................		50	50	50	50	50	50	50	50	50	50	50	50	597
32	Supplemental Capacity Wheeling.........		5	5	5	5	5	5	5	5	5	5	5	5	62
33	Townsend Garrison Transmission.........		845	845	845	845	845	845	845	845	845	845	845	845	10,136
34	Use of Facilities.....................		473	473	473	473	473	473	473	473	473	473	473	473	5,679
35	**Subtotal Other Transmission**		**4,575**	**4,557**	**4,607**	**4,614**	**4,623**	**4,553**	**4,630**	**4,846**	**4,790**	**4,806**	**4,789**	**4,608**	**55,997**
	Ancillary														
36	Scheduling Control & Dispatch..........		4,949	4,760	4,984	5,394	5,245	5,262	5,188	5,219	5,354	5,565	5,337	4,958	62,215
37	Generation Supplied Reactive...........		2,250	2,151	2,261	2,453	2,387	2,435	2,415	2,445	2,516	2,621	2,511	2,308	28,753
38	Regulation & Frequency Response........		1,401	1,392	1,698	1,722	1,583	1,425	1,227	1,170	1,046	1,134	1,174	1,064	16,036
39	Energy Imbalance......................		0	0	0	0	0	0	0	0	0	0	0	0	0
40	Operating Reserves - Spinning..........		1,660	1,649	2,011	2,039	1,875	1,688	1,454	1,386	1,239	1,343	1,391	1,260	18,994
41	Operating Reserves - Supplemental		1,660	1,649	2,011	2,039	1,875	1,688	1,454	1,386	1,239	1,343	1,391	1,260	18,994
42	**Subtotal Ancillary Services**		**11,920**	**11,601**	**12,964**	**13,647**	**12,964**	**12,498**	**11,738**	**11,605**	**11,395**	**12,007**	**11,804**	**10,849**	**144,991**
43	**Total Revenue**		**54,638**	**53,070**	**56,615**	**59,925**	**58,404**	**57,563**	**57,767**	**57,959**	**58,510**	**60,833**	**59,118**	**55,115**	**689,518**

Appendix J

Monthly Transmission Revenue, ($000)

	FY 2003		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Service	**Rate**	**Oct-02**	**Nov-02**	**Dec-02**	**Jan-03**	**Feb-03**	**Mar-03**	**Apr-03**	**May-03**	**Jun-03**	**Jul-03**	**Aug-03**	**Sep-03**	**FY 2003**
	General Transmission														
1	Formula Power Transmission................	FPT-02	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	3,566	42,787
2	Integration of Resources..................	IR-02	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	4,517	54,208
3	Network Transmission, Base................	NT-02	4,713	4,883	5,841	5,924	6,055	4,842	4,256	3,807	3,520	3,723	3,859	3,556	54,980
4	Network Transmission, Load Shaping........	NT-02	1,512	1,555	1,831	1,857	1,894	1,545	1,374	1,245	1,165	1,219	1,260	1,174	17,629
5	Network Contract Demand...................	NCD-02	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	5,197	62,359
6	Point to Point, Long-term Contracts.......	PTP-02	10,356	10,256	10,256	10,030	10,030	10,030	11,105	11,222	11,254	10,972	10,501	10,501	126,513
7	Point to Point, Daily Block 1............	PTP-02	433	511	540	829	723	837	923	1,042	1,047	967	929	285	9,066
8	Point to Point, Daily Block 2............	PTP-02	1,397	976	2,004	1,930	2,144	2,769	2,693	3,042	3,132	3,671	3,185	2,259	29,203
9	Point to Point, Hourly....................	PTP-02	1,510	871	773	2,442	1,650	1,893	747	663	1,294	1,303	1,063	777	14,987
10	**Subtotal General Rates, Network**		**33,200**	**32,332**	**34,525**	**36,292**	**35,775**	**35,195**	**34,377**	**34,300**	**34,692**	**35,134**	**34,076**	**31,832**	**411,731**
11	Southern Intertie, Long-term Contracts	IS-02	3,459	3,373	3,341	3,146	3,146	3,146	4,091	4,225	4,261	4,237	4,237	4,279	44,940
12	Southern Intertie, Daily Block 1..........	IS-02	114	90	56	137	33	167	269	68	173	524	350	460	2,443
13	Southern Intertie, Daily Block 2..........	IS-02	199	148	137	290	369	745	1,350	1,578	1,702	1,640	1,963	1,771	11,893
14	Southern Intertie, Hourly.................	IS-02	1,008	859	451	873	597	379	441	294	620	1,422	993	893	8,829
15	**Subtotal General Rates, Southern Intertie**		**4,780**	**4,470**	**3,984**	**4,446**	**4,144**	**4,438**	**6,151**	**6,166**	**6,756**	**7,822**	**7,543**	**7,404**	**68,104**
16	Montana Intertie..........................	IM-02	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Intertie East.............................	IE-02	0	0	0	0	0	0	0	0	0	0	0	0	0
18	DSI Delivery Charge.......................	UFT-02	630	630	630	630	630	630	630	630	630	630	630	630	7,559
19	Utility Delivery Charge...................	UD	849	844	1,053	1,029	1,058	905	834	754	682	719	723	679	10,129
20	**Subtotal General Transmission Rates**		**38,828**	**37,646**	**39,563**	**41,767**	**40,977**	**40,538**	**41,362**	**41,219**	**42,130**	**43,676**	**42,343**	**39,914**	**489,964**
	Other														
21	Annual Cost Rate..........................		115	115	115	115	115	115	115	115	115	115	115	115	1,375
22	Columbia Storage Power Exchange...........		21	21	21	21	21	21	0	0	0	0	0	0	127
23	Fiber.....................................		1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	19,800
24	Fiber Depreciation........................		58	58	58	58	58	58	58	58	58	58	58	58	696
25	Generation Integration....................		628	628	628	628	628	628	628	628	628	628	628	628	7,537
26	Irrigation Pumping Power..................		0	0	0	0	0	0	129	258	258	258	258	129	1,288
27	Nonfederal Participation Depreciation.....		278	278	278	278	278	278	278	278	278	278	278	278	3,335
28	Operations and Maintenance................		59	29	0	0	0	29	29	147	117	117	88	59	675
29	Personal Communications Wireless..........		369	369	369	369	369	369	369	369	369	369	369	369	4,430
30	Power Factor Penalty Charge...............		428	440	519	526	535	435	387	357	330	346	359	336	5,000
31	Remedial Action Scheme....................		50	50	50	50	50	50	50	50	50	50	50	50	597
32	Supplemental Capacity Wheeling............		5	5	5	5	5	5	0	0	0	0	0	0	27
33	Townsend Garrison Transmission............		845	845	845	845	845	845	845	845	845	845	845	845	10,136
34	Use of Facilities.........................		473	473	473	473	473	473	473	473	473	473	473	473	5,679
35	**Subtotal Other Transmission**		**4,978**	**4,960**	**5,010**	**5,017**	**5,026**	**4,956**	**5,011**	**5,227**	**5,171**	**5,187**	**5,170**	**4,989**	**60,702**
	Ancillary														
36	Scheduling Control & Dispatch.............		5,025	4,842	5,030	5,372	5,230	5,231	5,171	5,173	5,319	5,509	5,305	4,985	62,193
37	Generation Supplied Reactive..............		2,287	2,190	2,282	2,444	2,380	2,422	2,410	2,426	2,502	2,597	2,498	2,321	28,758
38	Regulation & Frequency Response...........		1,401	1,392	1,698	1,722	1,583	1,425	1,227	1,170	1,046	1,134	1,174	1,064	16,036
39	Energy Imbalance..........................		0	0	0	0	0	0	0	0	0	0	0	0	0
40	Operating Reserves - Spinning.............		1,660	1,649	2,011	2,039	1,875	1,688	1,454	1,386	1,239	1,343	1,391	1,260	18,994
41	Operating Reserves - Supplemental		1,660	1,649	2,011	2,039	1,875	1,688	1,454	1,386	1,239	1,343	1,391	1,260	18,994
42	**Subtotal Ancillary Services**		**12,033**	**11,722**	**13,032**	**13,616**	**12,943**	**12,454**	**11,715**	**11,540**	**11,346**	**11,926**	**11,760**	**10,889**	**144,975**
43	**Total Revenue**		**55,839**	**54,328**	**57,605**	**60,401**	**58,946**	**57,948**	**58,088**	**57,987**	**58,647**	**60,788**	**59,272**	**55,792**	**695,641**

APPENDIX K

Power Factor Penalty Charge

Appendix K
Power Factor Penalty Charge

Rate Calculation

		Capacitors (lagging reactive)	Reactors (leading reactive)
	Installed Reactive and Associated Capital Investment		
1	Total Installed kVAr	13,975,150	6,441,000
2	Capital Investment	$240,832,704	$107,692,655
	Annual Costs		
3	Annual Cost Ratio	7.85%	7.85%
4	Annual Cost of Interest And Amortization	$18,905,367	$8,453,873
5	Annual Cost of O&M	$4,154,498	$1,231,520
6	Total Annual Cost	$23,059,865	$9,685,393
7	**Calculation of Rate**		
8	Annual Cost per kVAr	$1.65	$1.50
9	Monthly Cost per kVAr	$0.14	$0.12
10	Power Factor Penalty Rate ($/kVAr-mo) 1/	**$0.28**	**$0.24**

Revenue Forecast

	Rate	Current 2/	Proposed 3/
11	Lagging Reactive Demand during HLHs: ($/kVAr/month)	0.08	0.28
12	Leading Reactive Demand during LLHs: ($/kVAr/month)	0.06	0.24
13	Reactive Energy (mills/kVArh	0.53	N/A
	Revenues		
14	Demand Charge - Lagging	$1,045	$4,000
15	Demand Charge - Leading	$288	$1,000
16	Energy Charge	$133	$0
17	Total	$1,466	$5,000

1/ The proposed rate is the monthly cost per kVAr doubled to reflect the penalty nature of the charge.

2/ Current revenues are for FY99.

3/ Based on an analysis of several customers, estimate that revenue will increase approximately 25% due to the change from a deadband which is based on a 0.95 power factor to one based on a 0.97 power factor.
Assumed also a 15 to 20 percent reduction in revenues as customers reduce their reactive demand due to the proposed penalty charge.