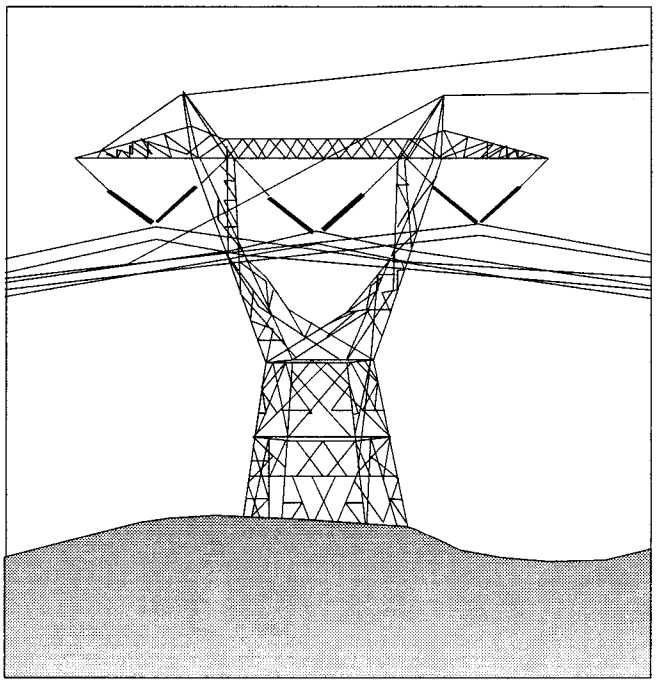
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

# 2002 FINAL TRANSMISSION PROPOSAL

## TRANSMISSION RATE STUDY

TR-02-FS-BPA-03



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AUGUST 2000

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TABLE OF CONTENTS

Page

LIST OF APPENDICES ..... iii
LIST OF TABLES ..... iv
COMMONLY USED ACRONYMS ..... v

1. INTRODUCTION ..... 1

1.1 Purpose ..... 1
1.2 Overview of the Basis for Rate Development ..... 2
1.2.1 Statutes ..... 2
1.2.2 Comparability ..... 3
1.2.3 Interbusiness Line Issues ..... 5
1.2.4 Settlement Agreement ..... 5
1.2.5 Contractual Arrangements ..... 7

2. RATE METHODOLOGY ..... 8

2.1 Rate Construct ..... 8
2.2 Cost ..... 9
2.2.1 Segmentation Study ..... 9
2.2.2 Revenue Requirement Study ..... 10
2.2.2.1 General Transfer Agreement (GTA) Cost ..... 11
2.2.3 Revenue Credits and Cost Adjustments ..... 12
2.3 Loads 13
2.3.1 Sales from Long-Term Contracts ..... 14
2.3.1.1 Network Rate Choice ..... 15
2.3.2 Short-Term and Hourly Sales ..... 16
2.3.3 Utility Delivery Loads ..... 17
2.4 Rate Calculations ..... 18
2.4.1 Ancillary Service Rates ..... 18
2.4.1.1 Cost ..... 19
2.4.1.2 Scheduling and Generation Reactive Rates ..... 20
2.4.2 Network and Southern Intertie Rates ..... 20
2.4.3 Montana Intertie and Eastern Intertie Rates ..... 21
2.4.4 Delivery Charge ..... 21

3. TRANSMISSION AND ANCILLARY SERVICE RATE SCHEDULES ..... 23

3.1 Formula Power Transmission Rates (FPT-02.1 and FPT-02.3) ..... 23
3.2 Integration of Resources Rate (IR-02) ..... 23
3.3 Network Integration Rate (NT-02) ..... 25
3.4 Point-to-Point Rate (PTP-02) ..... 26
3.5 Point-to-Point Intertie Service: Southern Intertie Rate (IS-02) and Montana Intertie Rate (IM-02) ..... 27
3.6 Townsend-Garrison Transmission Rate (TGT-02) and Eastern Intertie Rate (IE-02) ..... 28
3.7 Use-of-Facilities Transmission Rate (UFT-02) ..... 29
3.8 Advance Funding Rate (AF-02) ..... 29
3.9 Ancillary Services and Control Area Service Rate Schedule (ACS-02) ..... 29
3.9.1 Scheduling, System Control, and Dispatch (Scheduling) Service ..... 31
3.9.2 Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service ..... 32
3.9.3 Regulation and Frequency Response (Regulation) Service ..... 32
3.9.4 Energy Imbalance Service ..... 33
3.9.5 Operating Reserve -- Spinning Reserve Service ..... 34
3.9.6 Operating Reserve -- Supplemental Reserve Service ..... 35
3.9.7 CAS Regulation and Frequency Response Service ..... 36
3.9.8 CAS Generation Imbalance Service ..... 37
3.9.9 CAS Operating Reserve -- Spinning Reserve Service ..... 38
3.9.10 CAS Operating Reserve -- Supplemental Reserve Service ..... 39
3.10 Other Charges and Provisions ..... 40
3.10.1 Delivery Charge ..... 40
3.10.2 Failure to Comply Penalty Charge ..... 41
3.10.3 Power Factor Penalty Charge ..... 41
3.10.4 Rate Adjustment Due to FERC Order Under FPA §212 ..... 43
3.10.5 Reservation Fee ..... 43
3.10.6 Transmission and Ancillary Services Rate Discounts ..... 44
3.10.7 Unauthorized Increase Charge ..... 44
3.10.8 Incremental Cost Rates ..... 45
3.10.9 GTA Delivery Charge ..... 45

APPENDIX A: Long-Term Transmission Demands ..... A1

APPENDIX B: NT Base and Load Shaping Sales ..... B1

APPENDIX C: Utility Delivery Billing Determinants ..... C1

APPENDIX D: TBL Load Forecasting Methodology and Scope ..... D1

APPENDIX E: Network "Choice" Analysis ..... E1

APPENDIX F: FPT-02 Revenue Forecast ..... F1

APPENDIX G: DSI Delivery Charge Revenue ..... G1

APPENDIX H: Monthly Transmission Revenue ..... H1

APPENDIX I: Power Factor Penalty Charge ..... I1

LIST OF TABLES


| Table No. | Title | Page |
|---|---|---|
| 1. | Transmission Revenue Requirements | 46 |
| 2. | Revenue Credits | 48 |
| 3. | Rate Development Costs | 51 |
| 4. | Long-Term Transmission Sales | 52 |
| 5. | Short-Term Transmission Sales | 53 |
| 6. | FPT Rate | 54 |
| 7. | Ancillary Service Rates | 55 |
| 8. | PTP, NT and IS Rates | 56 |
| 9. | Montana Intertie Rate | 57 |
| 10. | Summary of Transmission and Ancillary Service Rates | 58 |
| 11. | Transmission Revenue Summary | 60 |

## 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 |
| BPA-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 |

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# 1. INTRODUCTION

## 1.1 Purpose

The Transmission Rate Study (TRS) presents an overview of the Bonneville Power Administration Transmission Business Line (BPA-TBL) rate design process for developing the proposed transmission and ancillary service rates. The rates calculated in the TRS are published in the Transmission and Ancillary Service Rate Schedules and General Rate Schedule Provisions. 2002 Final Transmission Record of Decision, TR-02-A-01, Appendix B. A summary of the proposed rates is shown in Table 10.

BPA-TBL proposes transmission rates for a two-year rate period—Fiscal Years (FYs) 2002 and 2003. (A fiscal year runs from October 1 through September 30.) The overall level and design of transmission and ancillary service 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. In addition, the final transmission rate proposal is guided by the Transmission Rates and Transmission Terms and Conditions Settlement Agreement (Settlement Agreement), negotiated by BPA-TBL and the rate case parties, which specifies various rate levels and other rate provisions. 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 resolved in the 2002 Power Rate Case, the Settlement Agreement, 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 Comparability

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.

As part of the Settlement Agreement, parties negotiated a proposed BPA-TBL Open Access Transmission Tariff (OATT) modeled on the FERC *pro forma* tariff. The proposed OATT includes terms and conditions of general applicability for open access transmission service, including Network Integration service and Point-to-Point service. In conjunction with the proposed open access transmission services, BPA-TBL proposes the Network Integration (NT) rate, Point-to-Point (PTP) rate, Southern Intertie

(IS) rate, Montana Intertie (IM) rate, and 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-OATT firm wheeling contracts.

### 1.2.3 Interbusiness Line Issues

Certain issues that affect the transmission and ancillary service rates have been 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 decided in the Power Rate Case is a treatment for costs of delivery of non-Federal power over third-party transmission systems, and the BPA Power Business Line's (BPA-PBL) financial support of the Delivery Charge. In calculating the proposed transmission and ancillary services rates, BPA-TBL has reflected the Administrator's decisions in the 2002 Final Power Rates Record of Decision, WP-02-A-02.

### 1.2.4 Settlement Agreement

BPA-TBL and the parties to the 2002 transmission rate proceeding entered into settlement discussions shortly after BPA-TBL's initial rates and terms and conditions

proposals were published and the formal proceedings commenced. BPA-TBL and the parties were concerned about the need to staff the BPA-TBL rate case, the terms and conditions proceeding, and efforts to form a regional transmission organization (RTO), all of which were all on a similar schedule. The formation of the RTO is driven by the deadlines in the Federal Energy Regulatory Commission's Order 2000. In addition, certain parties wanted to know what transmission services BPA-TBL would offer, and their associated transmission rates, prior to signing power sales contracts with the BPA-PBL in Fall 2000.

On April 20, 2000, the BPA-TBL and the parties settled the transmission and ancillary service rate levels, contingent upon settling the transmission terms and conditions of the BPA-TBL OATT by June 20, 2000. BPA-TBL and the parties settled the terms and conditions of BPA-TBL's OATT and some additional rate issues on June 20, 2000. The April 20 and June 20, 2000, settlement agreements, together with the proposed OATT, comprise the TR-02/TC-02 Settlement Agreement. 2002 Final Transmission Record of Decision, TR-02-A-01, Appendix A.

In addition to specifying the proposed rate levels for the transmission services offered by BPA-TBL, a number of Settlement Agreement provisions affect BPA-TBL's rate schedule provisions. The Settlement Agreement provisions associated with the OATT also cause some rate changes; e.g., the Network Contract Demand (NCD) service proposed by BPA-TBL in the 2002 Terms and Conditions Initial Proposal,

TC-02-E-BPA-01, was eliminated, and therefore, necessitates elimination of the associated NCD rate.

### 1.2.5 Contractual Arrangements

BPA-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. BPA-TBL will honor these agreements when setting and applying the new transmission rates.

## 2. RATE METHODOLOGY

### 2.1 Rate Construct

The transmission and ancillary service rates are set at levels specified in the Settlement Agreement. The Settlement Agreement provides i) rate levels which are the combination of the transmission rate (PTP, NT, IS) and the two required Ancillary Service rates (Scheduling, System Control, and Dispatch (Scheduling) Service and Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service); ii) specific rate levels (FPT, IR, Utility Delivery Charge); and iii) other information regarding ratesetting (DSI Delivery Charge, Unauthorized Increase Charge, short-term firm and non-firm rates). Rates that were not specified in the Settlement Agreement were to be set at levels not to exceed the rate levels in the 2002 Initial Transmission Rate Proposal (IM, IE, remaining Ancillary Service rates).

The relationship among the rates that exists for the current 1996 rates is continued with the proposed 2002 rates. The combination of the transmission rates (PTP, IR, and NT Base Charge) plus the two required Ancillary Service rates are set equal to each other. Again, as in 1996, the 2002 FPT rate is not included in this construct because of its different rate design. However, the increase in the FPT and IR rates (both of which include the two required Ancillary Services) is the same as the PTP increase, including the two required Ancillary Services.

Similar to the rate development for the current 1996 transmission rates, transmission service for BPA-PBL is accounted for in the same manner as for all other transmission

customers. To calculate rates and forecast revenues under proposed rates, BPA-TBL forecasts Network and Intertie transmission sales to each transmission customer under each service. The BPA-PBL uses the transmission system under Open Access service agreements and such use is forecasted in the same manner as for all other transmission customers. Firm PTP contract demands are assigned to BPA-PBL's grandfathered sales and exchanges, consistent with current treatment of these bundled contracts.

## 2.2 Cost

The Revenue Requirement Study (TR-02-FS-BPA-01) determines the test period revenue requirement for transmission and ancillary services. From that, the revenue requirement for each segment is determined. The Segmentation Study (TR-02-FS-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.

### 2.2.1 Segmentation Study

BPA-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 BPA-PBL revenue requirements and charged to the BPA-TBL through interbusiness line transfers. Final Power Rates Record of Decision, WP-02-A-02, at 5-69 – 5-70. *See* Revenue Requirement Study, TR-02-FS-BPA-01.

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. In addition, an ancillary services segment, further divided into six sub-segments, is developed.

### 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 FCRTS are compiled. Third, planned net revenues determined by the Administrator's financial objectives are calculated, if necessary, and added to the operating and net interest expense. *See* Revenue Requirement Study, TR-2-FS-BPA-01.

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 <u>General Transfer Agreement (GTA) Cost</u>**

The revenue requirement includes a cost item for "General Transfer Agreements for nonfederal power." *See* Table 1, lines 1.11 and 1.28. BPA-TBL shall pay up to $6.5 million annually to acquire Network-equivalent transmission for the non-Federal power purchases of GTA customers and shall roll this cost into the Network. 2002 Final Power Rates Record of Decision, WP-02-A-02, Chapter 9. BPA-TBL forecasts this cost to be $2.0 million per year.

### 2.2.3 Revenue Credits and Cost Adjustments

The segmented transmission revenue requirement is adjusted for revenue credits to arrive at the segment cost used to set the two required Ancillary Service rates and to determine the cost to be recovered from the BPA-PBL for Generation-Integration cost. The adjusted segmented revenue requirements are 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 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. *See* Table 3. Two additional adjustments are made to the revenue requirement to determine the rate development costs. 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 $0.543 million per year. The DSI IR and PTP contracts provide for a credit to be given to DSIs for BPA-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 cost of providing the stability reserves credit is segmented to the Southern Intertie. In addition, the difference between the DSI Delivery Segment net cost and the DSI Delivery Charge revenue is allocated to the Network.

Finally, the Generation Integration segment is comprised of transmission facilities that integrate Federal resources to the Network. The net cost of the Generation Integration segment, $7.302 million per year (Table 3, column A, line 3.17), is assigned wholly to the BPA-PBL and recovered through power rate charges. 2002 Final Power Rates Record of Decision, WP-02-A-02, at 5-69 - 5-70.

## 2.3 Loads

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 2000 short-term sales. The forecasts are shown on Tables 4 and 5. For the forecast of Network and Southern Intertie loads, current contract demands that are effective through the FY 2002 and 2003 rate period are determined first. Then, for the Network, BPA-TBL forecasted which Network service(s) it expects will be used by the remaining customers.

Customers have a number of choices with regard to Network transmission service and have options to switch their current service to an OATT service. BPA-TBL has four

long-term firm services on the Network. The proposed OATT provides a window to allow customers to convert their current service to an OATT service (PTP, 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 or during the 2002 rate period must select an OATT service.

### 2.3.1 Sales from Long-Term Contracts

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. Several PTP contracts that expire prior to FY 2002 were assumed to extend through the rate period. *See* Appendix A. PTP service on the Network and Southern Intertie is shown separately for BPA-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 PTP 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 BPA-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. PTP 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 PTP 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, and 17 months of actual sales (October 1998 through February 2000). The forecasted billing determinants for generating public utilities under the NT Base Charge and PTP 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 PTP services, and to estimate internal generation. The contract demands subtracted from the generating public utility's system load to forecast PTP 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, the PTP contract demand service is less expensive for utilities with high load factors and little

diversity from the total transmission system peak. NT service costs less than PTP contract demand service for low load factor customers with system peaks that differ from the overall transmission system peak. The forecast of customers' Network service is shown in Appendix E, Column B.

Seventeen 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. Fifteen of the 17 utilities are modeled under NT service, and two utilities are modeled under PTP service in contrast to the choice analysis result. Additionally, all PNGC utilities are assumed to take NT service.

### 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 a previous forecast for FY 2000 as the basis of the 2002/2003 rate period forecast. Short-term sales are adjusted for changes in long-term demands from FY 1999. Sensitivity coefficients of –0.700 and –0.442 between long-term and short-term sales are assumed for the Network and Southern Intertie, respectively. This forecasting model is calibrated to actual short-term revenues earned during the first seven months of FY 2000. Schematically, this forecast approach is represented as:

New Forecast = Old Forecast + (Demand Delta * Coefficient) + Calibration Term

The monthly, weekly, and daily sales produced by the forecasting model 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. This conversion relies on the frequency and duration of reservations in FY 1998 and FY 1999.

The inverse relationships between short-term and long-term sales (the sensitivity coefficients) account for the trade-off between these markets. Increases in long-term sales should result in decreased short-term sales. Long-term sales on the Southern Intertie have increased substantially in recent years. For the rate review period, long-term sales on the Southern Intertie are 2.5 times what they were forecast in the 1996 rate case. The 44 percent Southern Intertie relationship reflects the estimated sensitivity of BPA-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. The 70 percent coefficient for Network sales is an assumed 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

To implement the Settlement Agreement, the two required Ancillary Service rates (Scheduling Service and Generation Reactive Service) are calculated. When these two rates are calculated, the PTP, NT, and IS rates, and the Unauthorized Increase Charge can be determined. Of the remaining rates, the FPT and IR rates are calculated by increasing the current 1996 rates by 24.3%. The Settlement Agreement specifies the level of the Utility Delivery Charge and the methodology for the DSI Delivery Charge. Finally, the IM and IE rates, and the remaining Ancillary Service rates are set at the levels proposed in the Initial Proposal, consistent with provisions in the Settlement Agreement.

The Montana Intertie (IM) rate is based on BPA-TBL's annual cost under the TGT rate, and the capacity of BPA-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.

### 2.4.1 Ancillary Service Rates

The two required Ancillary Services rates, Scheduling, System Control, and Dispatch (Scheduling) Service and Reactive Supply and Voltage Control from Generation Sources (Generation Reactive) Service, are calculated in this Study. The Regulation and

Frequency Response Service rate, and Spinning and Supplemental Operating Reserve Services rates are set at the levels calculated in the Initial Proposal. TR-02-E-BPA-03, at 66.

Rates are not calculated for 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.

**2.4.1.1 <u>Cost</u>**

The two required Ancillary Service rates are based on the adjusted revenue requirement for Ancillary Services in Table 3. The revenue credit to the Ancillary Services revenue requirement is segmented among the Ancillary Services. Table 7, columns B and C. For customers taking FPT service, the two required services of Scheduling and Generation Reactive have not been unbundled. Therefore, the revenue requirements for these two required services are further adjusted to account for the portion of the revenue requirement being recovered through the FPT rates. Table 7, column D. The portion of FPT revenues associated with Ancillary Services is determined in Table 6 by prorating the revenues based on the relative proportions of Network rate development cost and Network-related Ancillary Service costs.

#### 2.4.1.2 Scheduling and Generation Reactive Rates

Scheduling Service and Generation Reactive Service rates are 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 Southern Intertie, excluding FPT use. Table 7, lines 7.3-7.4. 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 7, line 7.6. The resulting Scheduling rate is $0.164/kW/month, and the Generation Reactive rate is $0.066/kW/month. The rates are structured so that they may be used in conjunction with NT transmission service and PTP transmission service (PTP, IS, and IM rates), and 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.

### 2.4.2 Network and Southern Intertie Rates

After the two required Ancillary Service rates are calculated, the remaining Network rates (IR, PTP, and NT) and the Southern Intertie (IS) rate are calculated. *See* Table 8. First, the Base Charge (PTP, NT) of $1.013/kW/month is calculated by subtracting the two Ancillary Service rates from the Settlement Agreement cap of $1.243/kW/month. The IR rate is set at the Settlement Agreement cap of $1.243/kW/month. The NT Load Shaping Charge is the Settlement Agreement NT cap of $1.647/kW/month less the $1.243/kW/month cap. The IS rate of $1.159/kW/month is calculated by subtracting the two Ancillary Service rates from the Settlement Agreement IS cap of $1.389/kW/month.

Next, the PTP and IS daily Block 1 rate (first five days of a reservation), daily Block 2 rate (day 6 and beyond of a reservation), and the hourly rate are 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).

### 2.4.3 Montana Intertie and Eastern Intertie Rates

The Montana Intertie rate for long-term service, $14.87/kW/year, equals BPA-TBL's payment under the TGT rate for the Montana Intertie facilities divided by BPA-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.

The IE rate for nonfirm service is set at the level calculated in the Initial Proposal, 1.38 mills/kWh. The basis for this rate was the Eastern Intertie segment cost divided by the forecast amount of Colstrip energy. *See* TR-02-E-BPA-03, at Table 9. This rate is set pursuant to the Montana Intertie Agreement.

### 2.4.4 Delivery Charge

The Delivery Charge is charged to transmission customers taking delivery of power, either Federal or non-Federal, over transformers that are in the Utility or DSI Delivery Segments. The Utility Delivery Charge is set at the level specified in the Settlement

Agreement, $0.932/kW/month. The DSI Delivery Charge uses the UFT method to determine the charge to the customer.

## 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 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 3.10 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. Upon agreement, the IR service may be applied to points of delivery at an intertie.

Nonfirm wheeling from alternate Points of Integration, up to the contractually specified total Transmission Demands, may be done at the IR rate pursuant to IR contract provisions, and 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 IR demand charge is Total Transmission Demand. IR service does not allow assignment of Transmission Demand to third parties.

BPA-TBL proposes to continue the Short Distance Discount (SDD) which decreases the IR rate 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 equals i) the component of the IR Base rate associated with Ancillary Services, plus ii) a charge determined by multiplying the transmission-related component of the IR Base rate by the following formula:

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

The IR rate schedule also includes the Power Factor Penalty Charge, the Delivery Charge, the Failure to Comply Penalty Charge, and provisions detailing the circumstances under which the Ratchet Demand may be waived or reduced. *See* section 3.10 for further discussion of these provisions. The rate schedule also includes a

provision that allows IR customers to receive a credit for self-supply of Generation Reactive Service on an equivalent basis to the credit for PTP customers.

### 3.3 Network Integration Rate (NT-02)

The proposed NT-02 rate applies to Transmission Customers taking Network Integration Service under the OATT. NT Service provides transmission service for a customer's retail load. Charges for use of the Network include a Base Charge and a 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 Unauthorized Increase Charge for NT Service is applied to the difference between the Actual and Declared CSL.

The NT 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 Unauthorized Increase Charge; the Power Factor Penalty Charge; the Failure to Comply Penalty Charge; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 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 Point-to-Point Rate (PTP-02)

The proposed PTP-02 rate schedule applies to transmission customers taking PTP Transmission Service under the OATT. PTP Transmission Service may be used to serve native load and transactions with third parties over Network and Delivery facilities. The proposed PTP-02 rate includes a monthly rate for Long-Term Firm service, and downwardly flexible rates that apply to Short-Term Firm and Non-Firm service on the Network. The PTP-02 rate schedule includes all rates for all PTP services 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 provides two rates for short-term monthly, weekly, and daily service—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 reservations for hourly firm and non-firm 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 Increase Charge; the Reservation Fee; the Failure to Comply Penalty Charge; a credit for interruption of daily, weekly, and monthly nonfirm service; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions; and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 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 Intertie Service: Southern Intertie Rate (IS-02) and Montana Intertie Rate (IM-02)

The IS-02 and IM-02 rate schedules apply to transmission customers taking PTP Transmission Service on the Southern Intertie and Montana Intertie, respectively, under the terms and conditions of the OATT. 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 short-term firm and nonfirm service. The short-term 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 short-term firm and nonfirm service.

The IS and IM rate schedules also include: the requirement to purchase certain ancillary services; a credit for interruption of daily, weekly, and monthly nonfirm service; the Reservation Fee; the Power Factor Penalty Charge; an Unauthorized Increase Charge; the Failure to Comply Penalty Charge; notice of BPA-TBL's intent to charge incremental cost rates under specified conditions, and the Rate Adjustment Due to FERC Order Under FPA §212. *See* section 3.10 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.

### 3.6 Townsend-Garrison Transmission Rate (TGT-02) and Eastern Intertie Rate (IE-02)

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.

### 3.7 Use-of-Facilities Transmission Rate (UFT-02)

Wheeling transactions over specifically identified facilities occur under the UFT-02 formula-based rate. The UFT rate schedule provides for charges that vary with the customer's monthly use of the facilities, as well as charges designed to recover a fixed amount of costs from a customer regardless of how the customer's load may vary over the year. In addition, the Power Factor Penalty Charge and notice regarding ancillary services is included in the rate schedule.

### 3.8 Advance Funding Rate (AF-02)

This rate schedule allows BPA-TBL to collect the capital and related costs of specified BPA-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.

### 3.9 Ancillary Services and Control Area Service Rate Schedule (ACS-02)

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. BPA-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. BPA-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 BPA-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 BPA-TBL.

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

### 3.9.1 Scheduling, System Control, and Dispatch (Scheduling) Service

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 OATT. 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: capacity reservations for PTP (Network, Southern Intertie, Montana Intertie) 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 firm, short-term firm and non-firm service. Thus, the Scheduling charge for long-term firm service applies to NT and long-term PTP service. The short-term firm and nonfirm Scheduling charges apply to short-term firm and nonfirm PTP transmission service. All charges are downwardly flexible; any discounts would be offered consistent with section II.F of the GRSPs.

### 3.9.2 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 BPA-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 OATT. The description of the Scheduling Service rate schedule, above, also applies to the Generation Reactive rate schedule. In addition, the Generation Reactive Service rate includes a billing factor provision that recognizes that under some circumstances this Service may, in part, be self-provided.

### 3.9.3 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 BPA-TBL. The BPA-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 BPA-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 BPA-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.F of the GRSPs.

### 3.9.4 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). BPA-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.

### 3.9.5 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. BPA-TBL must offer this service when the transmission service is used to serve firm load (inside or outside of the BPA Control Area) from generation located in the BPA Control Area. The Transmission Customer must either purchase this service from BPA-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), Western Systems Coordinating Council (WSCC), and Northwest Power Pool (NWPP) 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.F 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 BPA-TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

### 3.9.6 Operating Reserve -- Supplemental Reserve Service

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 BPA-TBL must offer this service when the transmission service is used to serve firm load (inside or outside the BPA Control Area) from generation located in the BPA

Control Area. The Transmission Customer must either purchase this service from the BPA-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 NWPP 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.

### 3.9.7 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.

### 3.9.8 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). BPA-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.

### 3.9.9 CAS Operating Reserve -- Spinning Reserve Service

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 NWPP 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 BPA-TBL, or purchasing the energy at the hourly market index price that was effective when the contingency occurred.

### 3.9.10 CAS Operating Reserve -- Supplemental Reserve Service

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 NWPP 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.

## 3.10 Other Charges and Provisions

### 3.10.1 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 to determine the fixed monthly payment. The DSI Delivery Charge is designed to be independent of the actual DSI load; the charge is assessed whether or not the DSI is operating. If the DSI Delivery facilities serve only a DSI load and no other BPA-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 to calculate the monthly DSI Delivery Charge.

The Utility Delivery Charge, $0.932/kW/month, is assessed on the demand on the Utility Delivery facilities on the hour of the Monthly Transmission Peak Load.

### 3.10.2 Failure to Comply Penalty Charge

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 BPA-TBL. This includes, without limitation, failure of generators in the BPA Control Area or which directly connect to the FCRTS to change generation when directed to do so by BPA-TBL; failure to shed load in accordance with the OATT or any applicable agreements between BPA-TBL and the party; failure to curtail a schedule; and failure to respond to BPA-TBL operational orders in the time period specified by regional reliability criteria.

### 3.10.3 Power Factor Penalty Charge

BPA-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 the 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 BPA-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 I.

### 3.10.4 Rate Adjustment Due to FERC Order Under FPA §212

This provision, found in section II.D of the GRSPs, is included in the NT, PTP, IS, IM, and ACS rate schedules, which are designed to offer OATT 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.

### 3.10.5 Reservation Fee

The Reservation Fee, found in section II.E of the GRSPs, is included in the PTP, IS, and IM rate schedules. The Reservation Fee is applicable to PTP Transmission Customers who want to postpone the commencement of service by reserving "deferred" service for long-term PTP service through an advanced reservation, or requesting an extension of the Service Commencement Date specified in the executed Service Agreement. "Deferred" service is an advance reservation of long-term PTP service with a Service Commencement Date greater than one year from the request date. 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. For customers extending the Service Commencement Date; if BPA-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.

### 3.10.6 Transmission and Ancillary Services Rate Discounts

All transmission and ancillary service rates for service under the OATT may be discounted consistent with FERC policy and to the extent provided for in the relevant rate schedule. FERC requirements for applying discounts for specified in section II.F of the GRSPs.

### 3.10.7 Unauthorized Increase Charge

For rate schedules under the PTP tariff (PTP, IS, and IM rates) and the NT tariff (NT rate), BPA-TBL proposes to assess an Unauthorized Increase Charge (UIC) if PTP Transmission Service customers exceed their capacity reservations, or if an NT customer's Actual CSL is less than its Declared CSL on the monthly billing hour. The UIC, found in section II.G of the GRSPs, is set at four times the annual PTP rate, or $4.052/kW/month. Consistent with the Settlement Agreement, provision for waiving or reducing the UIC has been added.

For PTP service, BPA-TBL will determine unauthorized increases during all hours at the customer's PODs and PORs, the highest of which will be the billing factor for the UIC. Measurement of actual demands for one-way dynamically scheduled resources will be based on a 10-minute moving average measure; for two-way dynamic schedules, actual demands will be the instantaneous peak demand for the hour. The demands associated with all other schedules will be based on the 60-minute integrated demands or transmission schedules.

### 3.10.8 Incremental Cost Rates

BPA-TBL provides notice in most of the firm rate schedules that requests for new or increased firm transmission service that would require BPA-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. BPA-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.

### 3.10.9 GTA Delivery Charge

The GTA Delivery Charge, section II.H of the GRSPs, is a BPA-PBL charge for delivery of Federal power over non-Federal low-voltage facilities. As provided in the Settlement Agreement, this charge is set at the same level and charged at the same billing factor as the Utility Delivery Charge.

# TABLES

# Table 1
## Transmission Revenue Requirements
## ($000)

| | | (A) TBL Total | (B) Generation Integration | (C) Network | (D) Delivery Utility | (E) Delivery Industry | (F) Intertie Southern | (G) Intertie Eastern | (H) Ancillary Services |
|---|---|---|---|---|---|---|---|---|---|
| | **FY 2002** | | | | | | | | |
| 1. 1 | Gross Plant | 4,801,203 | 62,361 | 3,485,401 | 67,147 | 59,577 | 689,410 | 123,670 | 313,637 |
| 1. 2 | Lines | 2,187,952 | 16,398 | 1,867,778 | 1,260 | 1,200 | 202,494 | 98,822 | |
| 1. 3 | Stations | 2,299,614 | 45,963 | 1,617,623 | 65,887 | 58,377 | 486,916 | 24,848 | |
| 1. 4 | Net Plant | 3,136,059 | 49,881 | 2,265,598 | 56,451 | 49,691 | 418,586 | 80,001 | 215,851 |
| 1. 5 | Operating Expenses | 228,419 | 2,335 | 147,587 | 4,509 | 2,559 | 25,476 | 2,048 | 43,905 |
| 1. 6 | Generation Inputs | | | | | | | | |
| 1. 7 | Ancillary Services | 71,664 | | | | | | | 71,664 |
| 1. 8 | Station Service | 1,724 | 30 | 1,133 | 98 | 56 | 399 | 8 | |
| 1. 9 | Corp/Bureau | 3,701 | | 3,478 | 223 | | | | |
| 1.10 | Remedial Action Scheme (RAS) | 231 | | | | | 231 | | |
| 1.11 | Gen'l Transfer Agrmnts for nonfederal pwr | 2,000 | | 2,000 | | | | | |
| 1.12 | Leases | 5,267 | | 5,188 | 79 | | | | |
| 1.13 | Depreciation | 181,734 | 2,402 | 119,986 | 2,675 | 2,427 | 26,371 | 4,062 | 23,811 |
| 1.14 | Interest Credit from Facilities Sales | -752 | 0 | 0 | -376 | -376 | 0 | 0 | 0 |
| 1.15 | Interest | 177,060 | 2,816 | 127,914 | 3,187 | 2,806 | 23,633 | 4,517 | 12,187 |
| 1.16 | Net Revenues for Risk | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1.17 | Total Cost | 671,048 | 7,583 | 407,286 | 10,395 | 7,472 | 76,110 | 10,635 | 151,567 |

# Table 1
## Transmission Revenue Requirements
## ($000)

| | | (A) TBL Total | (B) Generation Integration | (C) Network | (D) Delivery Utility | (E) Delivery Industry | (F) Intertie Southern | (G) Intertie Eastern | (H) Ancillary Services |
|---|---|---|---|---|---|---|---|---|---|
| | **FY 2003** | | | | | | | | |
| 1.18 | Gross Plant | 4,929,534 | 63,020 | 3,678,284 | 69,046 | 61,476 | 694,354 | 26,750 | 336,604 |
| 1.19 | Lines | 2,190,961 | 16,511 | 1,965,664 | 1,656 | 1,596 | 203,938 | 1,596 | |
| 1.20 | Stations | 2,401,969 | 46,509 | 1,712,620 | 67,390 | 59,880 | 490,416 | 25,154 | |
| 1.21 | Net Plant | 3,206,660 | 48,224 | 2,359,217 | 56,001 | 49,506 | 400,961 | 76,598 | 216,153 |
| 1.22 | Operating Expenses | 222,543 | 2,276 | 143,848 | 4,394 | 2,494 | 24,832 | 1,996 | 42,703 |
| 1.23 | Generation Inputs | | | | | | | | |
| 1.24 | Ancillary Services | 71,664 | | | | | | | 71,664 |
| 1.25 | Station Service | 1,724 | 30 | 1,133 | 98 | 56 | 399 | 8 | |
| 1.26 | Corp/Bureau | 3,684 | | 3,458 | 226 | | | | |
| 1.27 | Remedial Action Scheme (RAS) | 231 | | | | | 231 | | |
| 1.28 | Gen'l Transfer Agrmnts for nonfederal pwr | 2,000 | | 2,000 | | | | | |
| 1.29 | Leases | 5,267 | | 5,188 | 79 | | | | |
| 1.30 | Depreciation | 194,009 | 2,473 | 128,861 | 2,803 | 2,548 | 27,065 | 4,161 | 26,098 |
| 1.31 | Interest Credit from Facilities Sales | -750 | 0 | 0 | -375 | -375 | 0 | 0 | 0 |
| 1.32 | Interest | 178,865 | 2,690 | 131,595 | 3,124 | 2,761 | 22,365 | 4,273 | 12,057 |
| 1.33 | Net Revenues for Risk | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1.34 | Total Cost | 679,237 | 7,469 | 416,083 | 10,349 | 7,484 | 74,892 | 10,438 | 152,522 |
| | **Average FY 2002 and FY 2003** | | | | | | | | |
| 1.35 | Total Cost | 675,143 | 7,526 | 411,685 | 10,372 | 7,478 | 75,501 | 10,537 | 152,045 |

# 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 | 15,500 | 17,500 | 16,500 |
| 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 | Reservation Fee | 828 | 1,656 | 1,242 |
| 2.15 | PBL Delivery Credit | 2,000 | 2,000 | 2,000 |
| 2.16 | Total | 48,681 | 50,865 | 49,773 |

| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|---|
| | **Credit Segmentation Factors (decimals)** | | Generation | | Delivery | | Intertie | | Ancillary |
| | | Total | Integration | Network | Utility | Industrial | Southern | Eastern | Services |
| 2.17 | AC Rate | 1.0000 | - | - | - | - | 1.0000 | - | - |
| 2.18 | CSPE Whlg | 1.0000 | 0.0364 | 0.9497 | 0.0138 | - | - | - | - |
| 2.19 | Fiber | 1.0000 | 0.0115 | 0.5399 | 0.0131 | 0.0116 | 0.0957 | 0.0183 | 0.3100 |
| 2.20 | Fiber Depreciation | 1.0000 | 0.0115 | 0.5399 | 0.0131 | 0.0116 | 0.0957 | 0.0183 | 0.3100 |
| 2.21 | Irrigation Pumping Power | 1.0000 | - | 1.0000 | - | - | - | - | - |
| 2.22 | NFP Depreciation | 1.0000 | - | - | - | - | 1.0000 | - | - |
| 2.23 | Operations and Maintenance | 1.0000 | 0.0159 | 0.9674 | 0.0116 | 0.0000 | 0.0051 | - | - |
| 2.24 | PC Wireless | 1.0000 | - | 1.0000 | - | - | - | - | - |
| 2.25 | Power Factor Penalty Charge | 1.0000 | - | 1.0000 | - | - | - | - | - |
| 2.26 | Remedial Action Scheme (RAS) | 1.0000 | - | - | - | - | 1.0000 | - | - |
| 2.27 | Supplemental Capacity Whlg | 1.0000 | 0.0370 | 0.9630 | - | - | - | - | - |
| 2.28 | TGT | 1.0000 | - | 0.0282 | - | - | - | 0.9718 | - |
| 2.29 | Use of Facilities (UFT) | 1.0000 | 0.0012 | 0.7145 | 0.0497 | - | 0.1560 | 0.0786 | - |
| 2.30 | Reservation Fee | 1.0000 | - | 0.8000 | - | - | 0.2000 | - | - |
| 2.31 | PBL Delivery Credit | 1.0000 | - | - | 1.0000 | - | - | - | - |

# 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** | | | | | | | | |
| 2.32 | AC Rate | - | - | - | - | 1,375 | - | - |
| 2.33 | CSPE Whlg | 10 | 255 | 4 | - | - | - | - |
| 2.34 | Fiber | 178 | 8,368 | 203 | 179 | 1,483 | 283 | 4,805 |
| 2.35 | Fiber Depreciation | 8 | 376 | 9 | 8 | 67 | 13 | 216 |
| 2.36 | Irrigation Pumping Power | - | 1,288 | - | - | - | - | - |
| 2.37 | NFP Depreciation | - | - | - | - | 3,335 | - | - |
| 2.38 | Operations and Maintenance | 11 | 653 | 8 | 0 | 3 | - | - |
| 2.39 | PC Wireless | - | 4,070 | - | - | - | - | - |
| 2.40 | Power Factor Penalty Charge | - | 5,000 | - | - | - | - | - |
| 2.41 | Remedial Action Scheme (RAS) | - | - | - | - | 597 | - | - |
| 2.42 | Supplemental Capacity Whlg | 2 | 60 | - | - | - | - | - |
| 2.43 | TGT | - | 285 | - | - | - | 9,850 | - |
| 2.44 | Use of Facilities (UFT) | 7 | 4,057 | 282 | - | 886 | 446 | - |
| 2.45 | Reservation Fee | - | 662 | - | - | 166 | - | - |
| 2.46 | PBL Delivery Credit | - | - | 2,000 | - | - | - | - |
| 2.47 | **Subtotal FY 2002** | **215** | **25,074** | **2,506** | **188** | **7,912** | **10,593** | **5,021** |
| **FY 2003 Revenue** | | | | | | | | |
| 2.48 | AC Rate | - | - | - | - | 1,375 | - | - |
| 2.49 | CSPE Whlg | 5 | 121 | 2 | - | - | - | - |
| 2.50 | Fiber | 200 | 9,448 | 230 | 203 | 1,674 | 320 | 5,425 |
| 2.51 | Fiber Depreciation | 8 | 376 | 9 | 8 | 67 | 13 | 216 |
| 2.52 | Irrigation Pumping Power | - | 1,288 | - | - | - | - | - |
| 2.53 | NFP Depreciation | - | - | - | - | 3,335 | - | - |
| 2.54 | Operations and Maintenance | 11 | 653 | 8 | 0 | 3 | - | - |
| 2.55 | PC Wireless | - | 4,430 | - | - | - | - | - |
| 2.56 | Power Factor Penalty Charge | - | 5,000 | - | - | - | - | - |
| 2.57 | Remedial Action Scheme (RAS) | - | - | - | - | 597 | - | - |
| 2.58 | Supplemental Capacity Whlg | 1 | 26 | - | - | - | - | - |
| 2.59 | TGT | - | 285 | - | - | - | 9,850 | - |
| 2.60 | Use of Facilities (UFT) | 7 | 4,057 | 282 | - | 886 | 446 | - |
| 2.61 | Reservation Fee | - | 1,324 | - | - | 331 | - | - |
| 2.62 | PBL Delivery Credit | - | - | 2,000 | - | - | - | - |
| 2.63 | **Subtotal FY 2003** | **231** | **27,009** | **2,531** | **211** | **8,269** | **10,629** | **5,641** |

# 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** | | | | | | | | |
| 2.64 | AC Rate | - | - | - | - | 1,375 | - | - |
| 2.65 | CSPE Whlg | 7 | 188 | 3 | - | - | - | - |
| 2.66 | Fiber | 189 | 8,908 | 217 | 191 | 1,579 | 302 | 5,115 |
| 2.67 | Fiber Depreciation | 8 | 376 | 9 | 8 | 67 | 13 | 216 |
| 2.68 | Irrigation Pumping Power | - | 1,288 | - | - | - | - | - |
| 2.69 | NFP Depreciation | - | - | - | - | 3,335 | - | - |
| 2.70 | Operations and Maintenance | 11 | 653 | 8 | 0 | 3 | - | - |
| 2.71 | PC Wireless | - | 4,250 | - | - | - | - | - |
| 2.72 | Power Factor Penalty Charge | - | 5,000 | - | - | - | - | - |
| 2.73 | Remedial Action Scheme (RAS) | - | - | - | - | 597 | - | - |
| 2.74 | Supplemental Capacity Whlg | 2 | 43 | - | - | - | - | - |
| 2.75 | TGT | - | 285 | - | - | - | 9,850 | - |
| 2.76 | Use of Facilities (UFT) | 7 | 4,057 | 282 | - | 886 | 446 | - |
| 2.77 | Reservation Fee | - | 993 | - | - | 248 | - | - |
| 2.78 | PBL Delivery Credit | - | - | 2,000 | - | - | - | - |
| 2.79 | **Average of FY 2002 and FY 2003** | **223** | **26,041** | **2,519** | **199** | **8,090** | **10,611** | **5,331** |

# Table 3
# Rate Development Costs
# ($000/Yr)

| | | (A) | (B) | (C) | (D) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|
| | | Generation | | Delivery | | Intertie | | Ancillary |
| | | Integration | Network | Utility | Industry | Southern | Eastern | Services |
| | **FY 2002** | | | | | | | |
| 3. 1 | Unadjusted Costs (Table 1) | 7,583 | 407,286 | 10,395 | 7,472 | 76,110 | 10,635 | 151,567 |
| 3. 2 | Revenue Credits (Table 2) | -215 | -25,074 | -2,506 | -188 | -7,912 | -10,593 | -5,021 |
| 3. 3 | DSI Stability Reserves 1/ | 0 | 0 | 0 | 0 | 542 | 0 | 0 |
| 3. 4 | Eastern Intertie Adjustment 2/ | 1 | 31 | 1 | 1 | 6 | -42 | 3 |
| 3. 5 | DSI Delivery Underrecovery | 0 | 1,495 | 0 | -1,495 | 0 | 0 | 0 |
| 3. 6 | Total | 7,369 | 383,738 | 7,889 | 5,790 | 68,746 | 0 | 146,549 |
| | **FY 2003** | | | | | | | |
| 3. 7 | Unadjusted Costs (Table 1) | 7,469 | 416,083 | 10,349 | 7,484 | 74,892 | 10,438 | 152,522 |
| 3. 8 | Revenue Credits (Table 2) | -231 | -27,009 | -2,531 | -211 | -8,269 | -10,629 | -5,641 |
| 3. 9 | DSI Stability Reserves 1/ | 0 | 0 | 0 | 0 | 544 | 0 | 0 |
| 3. 10 | Eastern Intertie Adjustment 2/ | -3 | -144 | -3 | -3 | -25 | 191 | -13 |
| 3. 11 | DSI Delivery Underrecovery | 0 | 1,480 | 0 | -1,480 | 0 | 0 | 0 |
| 3. 12 | Total | 7,235 | 390,410 | 7,815 | 5,790 | 67,143 | 0 | 146,868 |
| | **Average FY 2002 and FY 2003** | | | | | | | |
| 3.12 | Unadjusted Costs (Table 1) | 7,526 | 411,685 | 10,372 | 7,478 | 75,501 | 10,537 | 152,045 |
| 3.13 | Revenue Credits (Table 2) | -223 | -26,041 | -2,519 | -199 | -8,090 | -10,611 | -5,331 |
| 3.14 | DSI Stability Reserves 1/ | 0 | 0 | 0 | 0 | 543 | 0 | 0 |
| 3.15 | Eastern Intertie Adjustment 2/ | -1 | -56 | -1 | -1 | -9 | 75 | -5 |
| 3.16 | DSI Delivery Underrecovery | 0 | 1,487 | 0 | -1,487 | 0 | 0 | 0 |
| 3.17 | Total | 7,302 | 387,074 | 7,852 | 5,790 | 67,944 | 0 | 146,709 |

1/ Stability reserves credit based on DSI smelter load of 2855 MW (2002) and 2868 MW (2003) 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 Sales
# (Megawatts)

| | Transmission Rate Schedule | Units 1/ | (A) Oct | (B) Nov | (C) Dec | (D) Jan | (E) Feb | (F) Mar | (G) Apr | (H) May | (I) Jun | (J) Jul | (K) Aug | (L) Sep | (M) Annual Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Network** | | | | | | | | | | | | | | |
| | **FY 2002** | | | | | | | | | | | | | | |
| 4. 1 | Formula Power Transmission (FPT) | a_cd | 3,429 | 3,429 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,429 | **3,405** |
| 4. 2 | Integration of Resources (IR) | a_cd | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | **4,542** |
| 4. 3 | Point to Point (PTP) | a_cd | 10,881 | 10,881 | 10,881 | 10,886 | 10,886 | 11,156 | 11,156 | 11,156 | 11,156 | 11,156 | 11,156 | 11,156 | **11,042** |
| 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 Integration (Base Charge) | cp | 4,990 | 5,046 | 6,063 | 6,291 | 6,272 | 5,090 | 4,590 | 4,194 | 4,016 | 4,419 | 4,528 | 4,145 | **4,970** |
| 4. 6 | Subtotal Network | | 25,488 | 25,456 | 26,440 | 26,673 | 26,654 | 25,742 | 25,264 | 24,971 | 24,821 | 25,063 | 25,010 | 24,660 | **25,520** |
| | **FY 2003** | | | | | | | | | | | | | | |
| 4. 7 | Formula Power Transmission (FPT) | a_cd | 3,429 | 3,429 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,396 | 3,429 | **3,405** |
| 4. 8 | Integration of Resources (IR) | a_cd | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | 4,542 | **4,542** |
| 4. 9 | Point to Point (PTP) | a_cd | 11,831 | 11,831 | 11,831 | 11,645 | 11,645 | 11,645 | 11,645 | 11,645 | 11,645 | 11,535 | 11,535 | 11,535 | **11,664** |
| 4.10 | 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** |
| 4.11 | Network Integration (Base Charge) | cp | 5,059 | 5,126 | 6,155 | 6,376 | 6,365 | 5,164 | 4,671 | 4,273 | 4,092 | 4,500 | 4,606 | 4,216 | **5,050** |
| 4.12 | Subtotal Network | | 26,380 | 26,360 | 27,356 | 27,391 | 27,380 | 26,179 | 26,235 | 25,941 | 25,788 | 25,947 | 26,037 | 25,680 | **26,390** |
| 4.13 | Average FY 2002 and FY 2003 Network | | 25,934 | 25,908 | 26,898 | 27,032 | 27,017 | 25,961 | 25,750 | 25,456 | 25,304 | 25,505 | 25,523 | 25,170 | **25,955** |
| 4.14 | Network Integration (Load Shaping) FY 2002 | cp | 5,538 | 5,666 | 6,663 | 6,846 | 6,906 | 5,617 | 5,007 | 4,731 | 4,544 | 4,745 | 4,896 | 4,574 | **5,478** |
| 4.15 | Network Integration (Load Shaping) FY 2003 | cp | 5,602 | 5,740 | 6,750 | 6,929 | 6,998 | 5,690 | 5,073 | 4,796 | 4,606 | 4,812 | 4,960 | 4,631 | **5,549** |
| | **Southern Intertie** | | | | | | | | | | | | | | |
| | **FY 2002** | | | | | | | | | | | | | | |
| 4.16 | Intertie South (IS), North to South | m_cd | 129 | 129 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 129 | **104** |
| 4.17 | Intertie South (IS), South to North | m_cd | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | **271** |
| 4.18 | Point to Point Service | a_cd | 2,641 | 2,641 | 2,641 | 2,641 | 2,641 | 2,641 | 3,036 | 3,752 | 3,852 | 3,852 | 3,852 | 2,637 | **3,069** |
| 4.19 | Point to Point Service 2/ | m_cd | 405 | 317 | 317 | 317 | 317 | 317 | 317 | 420 | 448 | 462 | 462 | 462 | **380** |
| 4.20 | Subtotal Southern Intertie | | 3,446 | 3,358 | 3,325 | 3,325 | 3,325 | 3,325 | 3,720 | 4,539 | 4,667 | 4,681 | 4,681 | 3,499 | **3,824** |
| | **FY 2003** | | | | | | | | | | | | | | |
| 4.21 | Intertie South (IS), North to South | m_cd | 129 | 129 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 129 | **104** |
| 4.22 | Intertie South (IS), South to North | m_cd | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | 271 | **271** |
| 4.23 | Point to Point Service | a_cd | 2,637 | 2,637 | 2,637 | 2,437 | 2,437 | 2,437 | 2,437 | 2,836 | 2,836 | 2,781 | 2,781 | 2,381 | **2,606** |
| 4.24 | Point to Point Service 2/ | m_cd | 419 | 331 | 331 | 331 | 331 | 331 | 331 | 434 | 462 | 498 | 498 | 498 | **400** |
| 4.25 | Subtotal Southern Intertie | | 3,456 | 3,368 | 3,335 | 3,135 | 3,135 | 3,135 | 3,135 | 3,637 | 3,665 | 3,646 | 3,646 | 3,279 | **3,381** |
| 4.26 | Average FY 2002 and FY 2003 Southern Intertie | | 3,451 | 3,363 | 3,330 | 3,230 | 3,230 | 3,230 | 3,428 | 4,088 | 4,166 | 4,164 | 4,164 | 3,389 | **3,603** |

**1/** Annual contract demand (a_cd), monthly contract demand (m_cd), or coincidental peak (cp) which denotes contribution to TBL transmission system peak load.

**2/** Monthly demands from PBL grandfathered agreements.

# Table 5
# Short-Term Transmission Sales
# (Megawatts)

| | Short-term Product | Comment | Units | (A) Oct. | (B) Nov. | (C) Dec. | (D) Jan. | (E) Feb. | (F) Mar. | (G) Apr. | (H) May | (I) Jun. | (J) Jul. | (K) Aug. | (L) Sep. | (M) Annual Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Network** | | | | | | | | | | | | | | | |
| | **FY 2002** | | | | | | | | | | | | | | | |
| 5. 1 | Daily Block1 Produc | 1st 5 Days of Reservation: | MW-mos. | 282 | 195 | 280 | 962 | 501 | 550 | 394 | 382 | 494 | 589 | 410 | 294 | **445** |
| 5. 2 | Daily Block2 Produc | Reservations beyond 5th da | MW-mos. | 603 | 696 | 1,282 | 3,317 | 1,981 | 2,299 | 1,945 | 1,991 | 2,134 | 2,381 | 2,224 | 1,197 | **1,837** |
| 5. 3 | Hourly | | aMW | 367 | 380 | 648 | 1,776 | 1,123 | 1,182 | 998 | 985 | 1,121 | 1,232 | 1,093 | 636 | **962** |
| 5. 4 | | | | | | | | | | | | | | | | **3,244** |
| | **FY 2003** | | | | | | | | | | | | | | | |
| 5. 5 | Daily Block1 Produc | 1st 5 Days of Reservation: | MW-mos. | 290 | 202 | 288 | 1,004 | 527 | 573 | 382 | 369 | 477 | 575 | 391 | 277 | **446** |
| 5. 6 | Daily Block2 Produc | Reservations beyond 5th da | MW-mos. | 621 | 720 | 1,318 | 3,459 | 2,082 | 2,398 | 1,883 | 1,922 | 2,060 | 2,325 | 2,116 | 1,127 | **1,836** |
| 5. 7 | Hourly | | aMW | 378 | 393 | 667 | 1,852 | 1,180 | 1,233 | 967 | 951 | 1,083 | 1,204 | 1,040 | 599 | **962** |
| 5. 8 | | | | | | | | | | | | | | | | **3,245** |
| | **Average FY2002/2003** | | | | | | | | | | | | | | | |
| 5. 9 | Daily Block1 Produc | 1st 5 Days of Reservation: | MW-mos. | 286 | 199 | 284 | 983 | 514 | 562 | 388 | 375 | 485 | 582 | 401 | 286 | **445** |
| 5.10 | Daily Block2 Produc | Reservations beyond 5th da | MW-mos. | 612 | 708 | 1,300 | 3,388 | 2,032 | 2,349 | 1,914 | 1,957 | 2,097 | 2,353 | 2,170 | 1,162 | **1,837** |
| 5.11 | Hourly | | aMW | 373 | 387 | 657 | 1,814 | 1,151 | 1,208 | 982 | 968 | 1,102 | 1,218 | 1,067 | 618 | **962** |
| 5.12 | | | | | | | | | | | | | | | | **3,244** |
| | **Southern Intertie** | | | | | | | | | | | | | | | |
| | **FY 2002** | | | | | | | | | | | | | | | |
| 5.13 | Daily Block1 Produc | 1st 5 Days of Reservation: | MW-mos. | 103 | 72 | 62 | 281 | 26 | 92 | 173 | 39 | 93 | 393 | 233 | 141 | **142** |
| 5.14 | Daily Block2 Produc | Reservations beyond 5th da | MW-mos. | 253 | 166 | 214 | 840 | 412 | 576 | 1,206 | 1,241 | 1,270 | 1,719 | 1,819 | 755 | **873** |
| 5.15 | Hourly | | aMW | 64 | 43 | 49 | 201 | 84 | 119 | 252 | 229 | 249 | 378 | 367 | 164 | **183** |
| 5.16 | | | | | | | | | | | | | | | | **1,198** |
| | **FY 2003** | | | | | | | | | | | | | | | |
| 5.17 | Daily Block1 Product | 1st 5 Days of Reservations | MW-mos. | 102 | 71 | 62 | 318 | 28 | 98 | 201 | 48 | 117 | 490 | 284 | 150 | **164** |
| 5.18 | Daily Block2 Product | Reservations beyond 5th day | MW-mos. | 251 | 165 | 212 | 950 | 434 | 613 | 1,408 | 1,539 | 1,608 | 2,141 | 2,223 | 806 | **1,029** |
| 5.19 | Hourly | | aMW | 63 | 43 | 49 | 227 | 88 | 127 | 294 | 284 | 315 | 471 | 448 | 175 | **215** |
| 5.20 | | | | | | | | | | | | | | | | **1,409** |
| | **Average FY2002/2003** | | | | | | | | | | | | | | | |
| 5.21 | Daily Block1 Produc | 1st 5 Days of Reservation: | MW-mos. | 103 | 72 | 62 | 300 | 27 | 95 | 187 | 43 | 105 | 442 | 259 | 145 | **153** |
| 5.22 | Daily Block2 Produc | Reservations beyond 5th da | MW-mos. | 252 | 165 | 213 | 895 | 423 | 594 | 1,307 | 1,390 | 1,439 | 1,930 | 2,021 | 781 | **951** |
| 5.23 | Hourly | | aMW | 63 | 43 | 49 | 214 | 86 | 123 | 273 | 256 | 282 | 424 | 408 | 169 | **199** |
| 5.24 | | | | | | | | | | | | | | | | **1,303** |

# Table 6
## FPT Rate

| | | | (A) Source | (B) 2002 Rates 1/ |
|---|---|---|---|---|
| **I. FPT Rate** | | | | |
| 6. 1 | M-G Distance | ($/kW-mi-yr) | | 0.0503 |
| 6. 2 | M-G Miscellaneous Facilities | ($/kW-yr) | | 2.87 |
| 6. 3 | M-G Terminal | ($/kW-yr) | | 0.58 |
| 6. 4 | M-G Interconnection Terminal | ($/kW-yr) | | 0.52 |
| 6. 5 | S-S Transformation | ($/kW-yr) | | 5.41 |
| 6. 6 | S-S Interconnection Terminal | ($/kW-yr) | | 1.48 |
| 6. 7 | S-S Intermediate Terminal | ($/kW-yr) | | 2.09 |
| 6. 8 | S-S Distance | ($/kW-mi-yr) | | 0.4947 |
| **II. FPT Revenue Proration** | | | | |
| | **Sales (MW)** | | | |
| 6. 9 | Network | | Tables 4.13(M)+5.12(M) | 29,199 |
| 6.10 | Southern Intertie | | Tables 4.26(M)+5.24(M) | 4,906 |
| 6.11 | Total Sales | | 6.9 + 6.10 | 34,105 |
| | **Costs ($000)** | | | |
| 6.12 | Scheduling Control & Dispatch | | Table 7.1(A)+7.1(C) | 68,557 |
| 6.13 | Generation Reactive | | Table 7.2(A)+7.2(C) | 26,642 |
| 6.14 | Network Rate Development Costs | | Table 3.17(B) | 387,074 |
| 6.15 | Network-related Scheduling Control & Dispatch | | 6.12 * 6.9/6.11 | 58,695 |
| 6.16 | Network-related Generation Reactive | | 6.13 * 6.9/6.11 | 22,809 |
| 6.17 | Total Network Costs | | 6.14+6.15+6.16 | 468,578 |
| 6.18 | **FPT Revenue ($000)** | | Appendix F | 38,017 |
| | **FPT Revenue Associated with:** | | | |
| 6.19 | Network Transmission | | 6.18 * 6.14/6.17 | 31,404 |
| 6.20 | Scheduling Control & Dispatch | | 6.18 * 6.15/6.17 | 4,762 |
| 6.21 | Generation Reactive | | 6.18 * 6.16/6.17 | 1,851 |
| 6.22 | Total FPT Revenues | | 6.19+6.20+6.21 | 38,017 |

1/ 2002 FPT rate equals 1996 FPT rate times 1.243.

# Table 7
## Ancillary Service Rates

| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | FPT | | | RATES 2/ | | | | |
| | | Avg RRQ 6/ | Revenue Credits 1/ | | Credits 4/ | 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 / Rates** | | | | | | | | | | | |
| 7. 1 | Scheduling Control & Dispatch | 72,688 | 77% | -4,131 | -4,762 | 63,795 | 32,473 | 1.96 | 0.164 | 0.008 | 0.005 | 0.47 |
| 7. 2 | Generation Reactive | 26,814 | 3% | -172 | -1,851 | 24,791 | 31,348 | 0.79 | 0.066 | 0.003 | 0.002 | 0.19 |

| | **Transmission Sales (Rate Design MW)** | (MW) | Source |
|---|---|---|---|
| 7. 3 | Network (excluding FPT, no SDD) 5/ | 27,287 | Tables 4(M) and 5(M) |
| 7. 4 | Southern Intertie 5/ | 5,186 | Tables 4(M) and 5(M) |
| 7. 5 | Total Sales | 32,473 | 7. 3 + 7. 4 |
| 7. 6 | Less Gen Reactive Self Supply 3/ | -1,125 | |
| 7. 7 | Net Sales | 31,348 | 7. 5 + 7. 6 |

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

2/ Daily 1 (day 1-5) equals annual rate /(365*5/7), Daily 2 (day 6 and beyond) equals annual rate /365. Hourly is annual rate / ((8.760/168)*5*16).

3/ 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.

4/ Table 6.20(B) and 6.21(B).

5/ Short term sales from table 5 are adjusted by 7/5 for Daily Block 1 Sales, and by 168/(5*16) for Hourly Sales. Table 4 IR and PTP sales are discounted for Short Distance Discount by 256 MW.

6/ Revenue Requirement for Ancillary Services from Revenue Requirement Study, TR-02-FS-BPA-01.

# Table 8
## PTP, NT and IS Rates

| | | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | | Long Term Service | Short Term Service 1/ | | |
| | | Monthly | Daily 1 | Daily 2 | Hourly |
| | | ($/kW-mo) | ($/kW-day) | ($/kW-day) | (mills/kWh) |
| | **PTP** | | | | |
| 8. 1 | Settlement Agreement Cap | 1.243 | 0.057 | 0.041 | 3.58 |
| 8. 2 | Scheduling, Control & Dispatch | (0.164) | (0.008) | (0.005) | (0.47) |
| 8. 3 | Generation Reactive | (0.066) | (0.003) | (0.002) | (0.19) |
| 8. 4 | PTP | 1.013 | 0.046 | 0.034 | 2.92 |
| | **NT** | | | | |
| 8. 5 | Settlement Agreement Cap | 1.647 | | | |
| 8. 6 | Scheduling, Control & Dispatch | (0.164) | | | |
| 8. 7 | Generation Reactive | (0.066) | | | |
| 8. 8 | Base Rate | (1.013) | | | |
| 8. 9 | Load Shaping | 0.404 | | | |
| | **IS** | | | | |
| 8. 10 | Settlement Agreement Cap | 1.389 | 0.064 | 0.046 | 4.00 |
| 8. 11 | Scheduling, Control & Dispatch | (0.164) | (0.008) | (0.005) | (0.47) |
| 8. 12 | Generation Reactive | (0.066) | (0.003) | (0.002) | (0.19) |
| 8. 13 | IS | 1.159 | 0.053 | 0.039 | 3.34 |

1/ Daily 1 = Monthly * 12/365 * 7/5
Daily 2 = Monthly * 12/365
Hourly = Monthly * 12 / [(8.76/168)*5*16]

# Table 9
## Montana Intertie Rate

| | | (A) Source | (B) Units | (C) Amount |
|---|---|---|---|---|
| | **Montana Intertie (IM) Rate Calculation** | | | |
| 9. 1 | TBL's Payments in the Calculation of TGT | 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** |

# Table 10
## Summary of Transmission and Ancillary Services Rates

| | | Units | (A) 1996 Rates | (B) 2002 Rates | (C) Percent Change (B) / (A) |
|---|---|---|---|---|---|
| | **FPT-02.1 and FPT-02.3 Formula Power Transmission** | | | | |
| 10. 1 | M-G Distance | ($/kW-mi-yr) | 0.0405 | 0.0503 | 24.2% |
| 10. 2 | M-G Miscellaneous Facilities | ($/kW-yr) | 2.31 | 2.87 | 24.2% |
| 10. 3 | M-G Terminal | ($/kW-yr) | 0.47 | 0.58 | 23.4% |
| 10. 4 | M-G Interconnection Terminal | ($/kW-yr) | 0.42 | 0.52 | 23.8% |
| 10. 5 | S-S Transformation | ($/kW-yr) | 4.35 | 5.41 | 24.4% |
| 10. 6 | S-S Interconnection Terminal | ($/kW-yr) | 1.19 | 1.48 | 24.4% |
| 10. 7 | S-S Intermediate Terminal | ($/kW-yr) | 1.68 | 2.09 | 24.4% |
| 10. 8 | S-S Distance | ($/kW-mi-yr) | 0.3980 | 0.4947 | 24.3% |
| 10. 9 | Overall FPT Rate | ($/kW-yr) | 8.99 | 11.18 | 24.3% |
| 10.10 | Overall FPT Rate | ($/kW-mo) | 0.749 | 0.932 | 24.3% |
| | **IR-02 Integration of Resources** | | | | |
| 10.11 | Demand | ($/kW-mo) | 1.000 | 1.243 | 24.3% |
| | **NT-02 Network Integration** | | | | |
| 10.12 | Base Rate ($/kW-mo) | ($/kW-mo) | 1.000 | 1.013 | 1.3% |
| 10.10 | Load Shaping ($/kW-mo) | ($/kW-mo) | 0.539 | 0.404 | -25.0% |
| 10.14 | Base plus Load Shaping | ($/kW-mo) | 1.539 | 1.417 | -7.9% |
| | **PTP-02 Point-to-Point** | | | | |
| 10.15 | Demand | ($/kW-mo) | 1.000 | 1.013 | 1.3% |
| 10.16 | Daily Block 1 (day 1 thru 5) | ($/kW-day) | 0.046 | 0.046 | 0.0% |
| 10.17 | Daily Block 2 (day 6 and beyond) | ($/kW-day) | 0.033 | 0.034 | 3.0% |
| 10.18 | Hourly | (mills/kWh) | 2.52 | 2.92 | 15.9% |
| | **Unauthorized Increase Charge** | | | | |
| 10.19 | Demand | ($/kW-mo) | 12.000 | 4.052 | -66.2% |
| | **Utility Delivery** | | | | |
| 10.20 | Demand | ($/kW-mo) | 0.750 | 0.932 | 24.3% |
| | **IS-02 Southern Intertie** | | | | |
| 10.21 | Demand | ($/kW-mo) | 1.274 | 1.159 | -9.0% |
| 10.22 | Daily Block 1 (day 1 thru 5) | ($/kW-day) | 0.059 | 0.053 | -9.9% |
| 10.23 | Daily Block 2 (day 6 and beyond) | ($/kW-day) | 0.042 | 0.039 | -7.1% |
| 10.24 | Hourly | (mills/kWh) | 2.54 | 3.34 | 31.5% |
| | **IM-02 Montana Intertie** | | | | |
| 10.25 | Demand | ($/kW-mo) | 1.234 | 1.239 | 0.4% |
| 10.26 | Daily Block 1 (day 1 thru 5) | ($/kW-day) | 0.057 | 0.057 | 0.0% |
| 10.27 | Daily Block 2 (day 6 and beyond) | ($/kW-day) | 0.041 | 0.041 | 0.0% |
| 10.28 | Hourly | (mills/kWh) | 3.56 | 3.56 | 0.0% |
| | **Eastern Intertie** | | | | |
| 10.29 | IE-02 | (mills/kWh) | 1.68 | 1.38 | -17.9% |

# Table 10
## Summary of Transmission and Ancillary Services Rates

| | | Units | (A) 1996 Rates | (B) 2002 Rates | (C) Percent Change (B) / (A) |
|---|---|---|---|---|---|
| | **Power Factor Penalty Charge** | | | | |
| 10.30 | Demand -- Lagging | ($/kVAr-mo) | 0.08 | 0.28 | 250.0% |
| 10.31 | Demand -- Leading | ($/kVAr-mo) | 0.06 | 0.24 | 300.0% |
| 10.32 | Energy -- Lagging or Leading | ($/kVAr-hour) | 0.53 | n.a. | |
| | **Scheduling, System Control and Dispatch** | | | | |
| 10.33 | Demand | ($/kW-mo) | n.a. | 0.164 | n.a. |
| 10.34 | Daily Block 1 (day 1 thru 5) | ($/kW-day) | n.a. | 0.008 | n.a. |
| 10.35 | Daily Block 2 (day 6 and beyond) | ($/kW-day) | n.a. | 0.005 | n.a. |
| 10.36 | Hourly | (mills/kWh) | n.a. | 0.47 | n.a. |
| | **Reactive Supply and Voltage Control from Generation Sources** | | | | |
| 10.37 | Demand | ($/kW-mo) | n.a. | 0.066 | n.a. |
| 10.38 | Daily Block 1 (day 1 thru 5) | ($/kW-day) | n.a. | 0.003 | n.a. |
| 10.39 | Daily Block 2 (day 6 and beyond) | ($/kW-day) | n.a. | 0.002 | n.a. |
| 10.40 | Hourly | (mills/kWh) | n.a. | 0.19 | n.a. |
| | **Regulation and Frequency Response** | | | | |
| 10.41 | Hourly | (mills/kWh) | n.a. | 0.30 | n.a. |
| | **Energy Imbalance** | | | | |
| 10.42 | Hourly | (mills/kWh) | n.a. | 100.00 | n.a. |
| | **Operating Reserves** | | | | |
| 10.43 | Spinning | (mills/kWh) | n.a. | 8.27 | n.a. |
| 10.44 | Supplemental | (mills/kWh) | n.a. | 8.27 | n.a. |

# Table 11
## Transmission Revenue Summary
($000)

| | Service | Rate Schedule | (A) FY 2002 | (B) FY 2003 | (C) 2-Yr Total |
|---|---|---|---|---|---|
| | **General Transmission** | | | | |
| 1 | Formula Power Transmission | FPT-02 | 38,017 | 38,017 | 76,033 |
| 2 | Integration of Resources | IR-02 | 68,315 | 68,315 | 136,630 |
| 3 | Network Transmission, Base | NT-02 | 60,421 | 61,392 | 121,813 |
| 4 | Network Transmission, Load Shaping | NT-02 | 26,556 | 26,901 | 53,457 |
| 5 | Point to Point, Long-term Contracts | PTP-02 | 152,657 | 162,253 | 314,911 |
| 6 | Point to Point, Daily Block 1 | PTP-02 | 7,474 | 7,502 | 14,976 |
| 7 | Point to Point, Daily Block 2 | PTP-02 | 22,834 | 22,813 | 45,647 |
| 8 | Point to Point, Hourly | PTP-02 | 24,620 | 24,624 | 49,244 |
| 9 | **Subtotal General Rates, Network** | | **400,894** | **411,817** | **812,711** |
| 10 | Southern Intertie, Long-term Contracts | IS-02 | 53,188 | 47,023 | 100,211 |
| 11 | Southern Intertie, Daily Block 1 | IS-02 | 2,775 | 3,203 | 5,978 |
| 12 | Southern Intertie, Daily Block 2 | IS-02 | 12,479 | 14,725 | 27,204 |
| 13 | Southern Intertie, Hourly | IS-02 | 5,385 | 6,333 | 11,717 |
| 14 | **Subtotal General Rates, Southern Intertie** | | **73,826** | **71,284** | **145,110** |
| 15 | Montana Intertie | IM-02 | **0** | **0** | **0** |
| 16 | Intertie East | IE-02 | **0** | **0** | **0** |
| 17 | Utility Delivery Charge | Delv | **9,161** | **9,268** | **18,429** |
| 18 | DSI Delivery Charge | Delv | **5,790** | **5,790** | **11,581** |
| 19 | **Subtotal General Transmission Rates** | | **489,672** | **498,159** | **987,831** |
| | **Other** | | | | |
| 20 | Annual Cost Rate | | 1,375 | 1,375 | 2,751 |
| 21 | Columbia Storage Power Exchange | | 268 | 127 | 395 |
| 22 | Fiber | | 15,500 | 17,500 | 33,000 |
| 23 | Fiber Depreciation | | 696 | 696 | 1,392 |
| 24 | Generation Integration | | 7,369 | 7,235 | 14,603 |
| 25 | Irrigation Pumping Power | | 1,288 | 1,288 | 2,577 |
| 26 | Nonfederal Participation Depreciation | | 3,335 | 3,335 | 6,670 |
| 27 | Operations and Maintenance | | 675 | 675 | 1,350 |
| 28 | Personal Communications Wireless | | 4,070 | 4,430 | 8,500 |
| 29 | Power Factor Penalty Charge | | 5,000 | 5,000 | 10,000 |
| 30 | Remedial Action Scheme | | 597 | 597 | 1,194 |
| 31 | Reservation Fee | | 828 | 1,656 | 2,483 |
| 32 | Supplemental Capacity Wheeling | | 62 | 27 | 89 |
| 33 | Townsend Garrison Transmission | | 10,136 | 10,136 | 20,271 |
| 34 | Use of Facilities | | 5,679 | 5,679 | 11,358 |
| 35 | **Subtotal Other Transmission** | | **56,877** | **59,755** | **116,633** |
| | **Ancillary** | | | | |
| 36 | Scheduling Control & Dispatch | | 53,609 | 55,062 | 108,671 |
| 37 | Generation Reactive | | 20,633 | 21,257 | 41,890 |
| 38 | Regulation & Frequency Response | | 16,038 | 15,663 | 31,701 |
| 39 | Energy Imbalance | | 0 | 0 | 0 |
| 40 | Operating Reserves - Spinning | | 18,996 | 17,903 | 36,899 |
| 41 | Operating Reserves - Supplemental | | 18,996 | 17,889 | 36,885 |
| 42 | **Subtotal Ancillary Services** | | **128,273** | **127,773** | **256,046** |
| 43 | **Total Revenue** | | **674,822** | **685,687** | **1,360,509** |
| 44 | **Total TBL Table 1 Costs** | | **671,048** | **679,237** | **1,350,285** |
| 45 | **Revenue Longfall (Shortfall)** | | **3,774** | **6,450** | **10,224** |

# APPENDICES

APPENDIX A

# Long-Term Transmission Demands

# Appendix A

## Long-term Transmission Demands, FY2002

## (Megawatts)

**FY 2002**

| | CUSTOMER | RATE | CONTRACT | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 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 |
| 2 | 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 |
| 3 | 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 |
| 4 | 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 |
| 5 | 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 |
| 6 | 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 |
| 7 | 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 |
| 8 | 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 |
| 9 | 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 |
| 10 | 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 |
| 11 | 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 |
| 12 | 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 |
| 13 | PEND OREILLE COUNTY PUD N | FPT.1 | MS79-90BP92488 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.1 |
| 14 | 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 |
| 15 | 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 |
| 16 | POWER RESOURCES GROUP (ar | 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 |
| 17 | PUGET SOUND ENERGY, 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 |
| 18 | TACOMA PUBLIC UTILITIES | 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 |
| 19 | WASHINGTON WATER POWER (A | 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 |
| 20 | WASHINGTON WATER POWER (A | 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 |
| 21 | 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 |
| 22 | 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 |
| 23 | 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 |
| 24 | TACOMA PUBLIC UTILITIES | 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 |
| | TOTAL FPT | | | 3,429.4 | 3,429.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,429.4 | 3,405.0 |
| 25 | 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 |
| 26 | EUGENE WATER & ELECTRIC B | IR | MS79-86BP91651 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 |
| 27 | 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 |
| 28 | 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 |
| 29 | KITTITAS COUNTY PUD NO 1 | IR | MS79-86BP91845 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 |
| 30 | 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 |
| 31 | PORTLAND GENERAL ELECTRIC | IR | MS79-89BP92273 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 |
| 32 | PORTLAND GENERAL ELECTRIC | IR | MS79-89BP92273 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 |
| 33 | PUGET SOUND ENERGY, INC. | IR | MS79-94BP93947 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 |
| 34 | PUGET SOUND ENERGY, 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 |
| 35 | PUGET SOUND ENERGY, 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 |
| 36 | PUGET SOUND ENERGY, 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 |
| 37 | PUGET SOUND ENERGY, 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 |
| 38 | PUGET SOUND ENERGY, 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 |
| 39 | PUGET SOUND ENERGY, 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 |
| 40 | PUGET SOUND ENERGY, 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 |
| 41 | PUGET SOUND ENERGY, 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 |
| | TOTAL IR | | | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 |
| 42 | 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 |
| 43 | ALCOA/NORTHWEST ALLOYS,IN | PTP | 01TX-ALOCA_WENATCHEE | 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 |
| 44 | BONNEVILLE POWER BUSINESS | PTP | 96MS-95363 | 1,482.0 | 1,482.0 | 1,482.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,478.0 | 1,479.0 |
| 45 | 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 |
| 46 | CLATSKANIE COUNTY PUD | PTP | 97TX-10040_FollowOn | 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 |
| 47 | 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 |
| 48 | 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 |
| 49 | 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 |

# Appendix A

Long-term Transmission Demands, FY2002

(Megawatts)

**FY 2002**

| | CUSTOMER | RATE | CONTRACT | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 50 | EMERALD PUD | PTP | 01TX-EPUD_AE_INPUT | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 |
| 51 | ENGAGE ENERGY | PTP | 98TX-10158 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 270.0 | 270.0 | 270.0 | 270.0 | 270.0 | 270.0 | 270.0 | 157.5 |
| 52 | EUGENE WATER & ELECTRIC B | PTP | 01TX-EWEB_AE_INPUT | 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 |
| 53 | GOLDENDALE (COLUMBIA ALUM | PTP | 96MS-96109 | 326.0 | 326.0 | 326.0 | 335.0 | 335.0 | 335.0 | 335.0 | 335.0 | 335.0 | 335.0 | 335.0 | 335.0 | 332.7 |
| 54 | 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 |
| 55 | GRAYS HARBOR COUNTY PUD N | PTP | 96MS-96083 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 |
| 56 | GRAYS HARBOR COUNTY PUD N | PTP | 96MS-96083 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 |
| 57 | 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 |
| 58 | IDAHO FALLS, CITY OF | PTP | 96MS-96105 | 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 |
| 59 | IDAHO POWER COMPANY | PTP | 96MS-96108 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 |
| 60 | IDAHO POWER COMPANY | PTP | 96MS-96108 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 |
| 61 | INTALCO ALUMINUM CORPORAT | PTP | 00TX-INTALCO | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 |
| 62 | 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 |
| 63 | KAISER ALUMINUM COMPANY | PTP | 97TX-96107DS | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 |
| 64 | KLICKITAT COUNTY PUD NO 1 | PTP | 97TX-10038 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 |
| 65 | 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 |
| 66 | OREGON METALLURGICAL CORP | PTP | 01TX-ORMET@RC | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 |
| 67 | 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 |
| 68 | PACIFIC POWER & LIGHT COM | PTP | 96MS-96035 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 |
| 69 | PACIFIC POWER & LIGHT COM | PTP | 00TX-PPLGSN | 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 |
| 70 | PEND OREILLE COUNTY PUD N | PTP | 97TX-10090 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 71 | PEND OREILLE COUNTY PUD N | PTP | 97TX-10090 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 |
| 72 | PORTLAND GENERAL ELECTRIC | PTP | 98TX-10174 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 73 | POWEREX: BC HYDRO EXPORT | 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 |
| 74 | POWEREX: BC HYDRO EXPORT | PTP | 99TX-10251 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 |
| 75 | 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 |
| 76 | SEATTLE, CITY OF | PTP | 96MS-96018 | 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 |
| 77 | SNOHOMISH COUNTY PUD NO 1 | PTP | 96MS-96092 | 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 |
| 78 | SPRINGFIELD, CITY OF, UTI | PTP | 97TX-96038 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 |
| 79 | SPRINGFIELD, CITY OF, UTI | PTP | 97TX-96038 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 |
| 80 | TACOMA PUBLIC UTILITIES | 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 |
| 81 | TACOMA PUBLIC UTILITIES | PTP | 01TX-TCL_GGILBERT | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 | 410.0 |
| 82 | VANALCO, INC | PTP | 00TX-VANALCO | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 |
| 83 | WASHINGTON WATER POWER (A | 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 |
| 84 | WASHINGTON WATER POWER (A | 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 |
| | TOTAL PTP | | | 12,526.2 | 12,438.2 | 12,438.2 | 12,443.2 | 12,443.2 | 12,713.2 | 12,735.2 | 12,838.2 | 12,866.2 | 12,705.2 | 12,543.2 | 12,543.2 | 12,602.7 |
| 85 | BONNEVILLE POWER BUSINESS | IS | 96MS-95363 | 1,610.0 | 1,610.0 | 1,610.0 | 1,610.0 | 1,610.0 | 1,610.0 | 2,005.0 | 2,005.0 | 2,005.0 | 2,005.0 | 2,005.0 | 1,605.0 | 1,774.2 |
| 86 | 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 |
| 87 | 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 |
| 88 | 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 |
| 89 | 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 |
| 90 | 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 |
| 91 | 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 |
| 92 | POWEREX: BC HYDRO EXPORT | IS | 99TX-10251 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 521.0 | 521.0 | 521.0 | 521.0 | 105.0 | 243.6 |
| 93 | POWEREX: BC HYDRO EXPORT | IS | 99TX-10230 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 300.0 | 400.0 | 400.0 | 400.0 | 1.0 | 125.1 |
| 94 | TACOMA PUBLIC UTILITIES | 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 | 8.3 |
| 95 | TRANSALTA ENERGY MARKETIN | IS | 98TX-10172 | 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 |
| | TOTAL IS | | | 3,446.0 | 3,358.0 | 3,325.0 | 3,325.0 | 3,325.0 | 3,325.0 | 3,720.0 | 4,539.0 | 4,667.0 | 4,681.0 | 4,681.0 | 3,499.0 | 3,824.3 |

# Appendix A

## Long-term Transmission Demands, FY2003

## (Megawatts)

**FY 2003**

| | CUSTOMER | RATE | CONTRACT | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 96 | 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 |
| 97 | 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 |
| 98 | 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 |
| 99 | 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 |
| 100 | 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 |
| 101 | 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 |
| 102 | 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 |
| 103 | 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 |
| 104 | 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 |
| 105 | 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 |
| 106 | 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 |
| 107 | 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 |
| 108 | PEND OREILLE COUNTY PUD N | FPT.1 | MS79-90BP92488 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.0 | 36.1 |
| 109 | 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 |
| 110 | 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 |
| 111 | POWER RESOURCES GROUP (ar | 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 |
| 112 | PUGET SOUND ENERGY, 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 |
| 113 | TACOMA PUBLIC UTILITIES | 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 |
| 114 | WASHINGTON WATER POWER (A | 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 |
| 115 | WASHINGTON WATER POWER (A | 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 |
| 116 | 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 |
| 117 | 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 |
| 118 | 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 |
| 119 | TACOMA PUBLIC UTILITIES | 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 |
| | TOTAL FPT | | | 3,429.4 | 3,429.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,396.4 | 3,429.4 | 3,405.0 |
| 120 | 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 |
| 121 | EUGENE WATER & ELECTRIC B | IR | MS79-86BP91651 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 | -19.6 |
| 122 | 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 |
| 123 | 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 |
| 124 | KITTITAS COUNTY PUD NO 1 | IR | MS79-86BP91845 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 | -0.6 |
| 125 | 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 |
| 126 | PORTLAND GENERAL ELECTRIC | IR | MS79-89BP92273 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 | 2,243.0 |
| 127 | PORTLAND GENERAL ELECTRIC | IR | MS79-89BP92273 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 | -183.9 |
| 128 | PUGET SOUND ENERGY, INC. | IR | MS79-94BP93947 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 | 1,157.0 |
| 129 | PUGET SOUND ENERGY, 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 |
| 130 | PUGET SOUND ENERGY, 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 |
| 131 | PUGET SOUND ENERGY, 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 |
| 132 | PUGET SOUND ENERGY, 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 |
| 133 | PUGET SOUND ENERGY, 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 |
| 134 | PUGET SOUND ENERGY, 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 |
| 135 | PUGET SOUND ENERGY, 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 |
| 136 | PUGET SOUND ENERGY, 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 |
| | TOTAL IR | | | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 | 4,542.2 |
| 137 | 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 |
| 138 | ALCOA/NORTHWEST ALLOYS,IN | PTP | 01TX-ALOCA_WENATCHEE | 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 |
| 139 | BONNEVILLE POWER BUSINESS | PTP | 96MS-95363 | 1,478.0 | 1,478.0 | 1,478.0 | 1,278.0 | 1,278.0 | 1,278.0 | 1,278.0 | 1,278.0 | 1,278.0 | 1,168.0 | 1,168.0 | 1,168.0 | 1,300.5 |
| 140 | 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 | 1,728.1 |
| 141 | CLATSKANIE COUNTY PUD | PTP | 97TX-10040_FollowOn | 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 |
| 142 | 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 |
| 143 | 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 |
| 144 | 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 |
| 145 | EMERALD PUD | PTP | 01TX-EPUD_AE_INPUT | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 |

# Appendix A
## Long-term Transmission Demands, FY2003
## (Megawatts)

**FY 2003**

| | CUSTOMER | RATE | CONTRACT | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | ANNUAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 146 | ENGAGE ENERGY | 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 |
| 147 | EUGENE WATER & ELECTRIC B | PTP | 01TX-EWEB_AE_INPUT | 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 |
| 148 | GOLDENDALE (COLUMBIA ALUM | PTP | 96MS-96109 | 335.0 | 335.0 | 335.0 | 349.0 | 349.0 | 349.0 | 349.0 | 349.0 | 349.0 | 349.0 | 349.0 | 349.0 | 345.5 |
| 149 | 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 |
| 150 | GRAYS HARBOR COUNTY PUD N | PTP | 96MS-96083 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 | 212.0 |
| 151 | GRAYS HARBOR COUNTY PUD N | PTP | 96MS-96083 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 | -5.9 |
| 152 | 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 |
| 153 | IDAHO FALLS, CITY OF | PTP | 96MS-96105 | 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 |
| 154 | IDAHO POWER COMPANY | PTP | 96MS-96108 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 |
| 155 | IDAHO POWER COMPANY | PTP | 96MS-96108 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 | -9.1 |
| 156 | INTALCO ALUMINUM CORPORAT | PTP | 00TX-INTALCO | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 | 475.0 |
| 157 | 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 |
| 158 | KAISER ALUMINUM COMPANY | PTP | 97TX-96107DS | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 | 345.0 |
| 159 | KLICKITAT COUNTY PUD NO 1 | PTP | 97TX-10038 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 | 76.1 |
| 160 | NATIONAL ENERGY SYSTEMS C | PTP | 00TX-SE2@RC | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 | 660.0 |
| 161 | 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 |
| 162 | OREGON METALLURGICAL CORP | PTP | 01TX-ORMET@RC | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 |
| 163 | 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 |
| 164 | PACIFIC POWER & LIGHT COM | PTP | 96MS-96035 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 | -10.9 |
| 165 | PACIFIC POWER & LIGHT COM | PTP | 00TX-PPLGSN | 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 |
| 166 | PEND OREILLE COUNTY PUD N | PTP | 97TX-10090 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 167 | PEND OREILLE COUNTY PUD N | PTP | 97TX-10090 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 | -2.4 |
| 168 | PORTLAND GENERAL ELECTRIC | PTP | 98TX-10174 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 169 | POWEREX: BC HYDRO EXPORT | 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 |
| 170 | POWEREX: BC HYDRO EXPORT | PTP | 99TX-10251 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 | 60.0 |
| 171 | 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 |
| 172 | SEATTLE, CITY OF | PTP | 96MS-96018 | 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 |
| 173 | SNOHOMISH COUNTY PUD NO 1 | PTP | 96MS-96092 | 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 |
| 174 | SPRINGFIELD, CITY OF, UTI | PTP | 97TX-96038 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 |
| 175 | SPRINGFIELD, CITY OF, UTI | PTP | 97TX-96038 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 | -23.6 |
| 176 | TACOMA PUBLIC UTILITIES | 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 |
| 177 | TACOMA PUBLIC UTILITIES | PTP | 01TX-TCL_GGILBERT | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 | 425.0 |
| 178 | VANALCO, INC | PTP | 00TX-VANALCO | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 | 170.0 |
| 179 | WASHINGTON WATER POWER (A | 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 |
| 180 | WASHINGTON WATER POWER (A | 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 |
| | TOTAL PTP | | | 13,350.2 | 13,262.2 | 13,262.2 | 13,076.2 | 13,076.2 | 13,076.2 | 13,626.2 | 13,729.2 | 13,757.2 | 13,508.2 | 13,492.2 | 13,492.2 | 13,392.3 |
| 181 | BONNEVILLE POWER BUSINESS | IS | 96MS-95363 | 1,605.0 | 1,605.0 | 1,605.0 | 1,405.0 | 1,405.0 | 1,405.0 | 1,405.0 | 1,405.0 | 1,405.0 | 1,350.0 | 1,350.0 | 1,350.0 | 1,441.3 |
| 182 | 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 |
| 183 | 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 |
| 184 | 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 |
| 185 | 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 |
| 186 | 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 |
| 187 | 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 |
| 188 | POWEREX: BC HYDRO EXPORT | IS | 99TX-10251 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 | 105.0 |
| 189 | POWEREX: BC HYDRO EXPORT | IS | 99TX-10230 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 400.0 | 400.0 | 400.0 | 400.0 | 0.0 | 133.9 |
| 190 | TACOMA PUBLIC UTILITIES | 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 | 8.3 |
| 191 | TRANSALTA ENERGY MARKETIN | IS | 98TX-10172 | 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 |
| | TOTAL IS | | | 3,456.0 | 3,368.0 | 3,335.0 | 3,135.0 | 3,135.0 | 3,135.0 | 3,135.0 | 3,637.0 | 3,665.0 | 3,646.0 | 3,646.0 | 3,279.0 | 3,381.1 |

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 COMPAN | 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 COMPAN | 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 COMPAN | 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 COMPAN | 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 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.10 | 0.43 | 0.75 | 1.36 | 1.41 | 0.36 |
| 14 | ASOTIN COUNTY PUD | 201 | | LS | recent pwr bills | 2002 | 0.08 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.10 | 0.43 | 0.75 | 1.36 | 1.41 | 0.36 |
| 15 | ASOTIN COUNTY PUD | 201 | | BASE | recent pwr bills | 2003 | 0.08 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.11 | 0.43 | 0.75 | 1.36 | 1.41 | 0.36 |
| 16 | ASOTIN COUNTY PUD | 201 | | LS | recent pwr bills | 2003 | 0.08 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.11 | 0.43 | 0.75 | 1.36 | 1.41 | 0.36 |
| 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 | BENTON COUNTY PUD NO 1 | 203 | | BASE | TBL load forecast | 2002 | 220.61 | 214.24 | 272.23 | 310.49 | 300.03 | 223.04 | 209.68 | 210.39 | 253.01 | 305.89 | 332.18 | 229.23 | 256.75 |
| 22 | BENTON COUNTY PUD NO 1 | 203 | | LS | TBL load forecast | 2002 | 221.96 | 215.59 | 273.58 | 311.84 | 301.38 | 224.39 | 210.89 | 211.60 | 254.22 | 307.10 | 333.39 | 230.44 | 258.03 |
| 23 | BENTON COUNTY PUD NO 1 | 203 | | BASE | TBL load forecast | 2003 | 224.06 | 217.60 | 276.46 | 315.29 | 304.67 | 226.53 | 214.04 | 214.75 | 258.02 | 311.69 | 338.37 | 233.88 | 261.28 |
| 24 | BENTON COUNTY PUD NO 1 | 203 | | LS | TBL load forecast | 2003 | 225.27 | 218.81 | 277.67 | 316.50 | 305.88 | 227.74 | 214.04 | 214.75 | 258.02 | 311.69 | 338.37 | 233.88 | 261.89 |
| 25 | BENTON RURAL ELECTRIC ASS | 303 | | BASE | TBL load forecast | 2002 | 68.64 | 54.98 | 70.21 | 71.16 | 75.96 | 53.82 | 49.52 | 54.97 | 66.01 | 79.41 | 94.00 | 77.88 | 68.05 |
| 26 | BENTON RURAL ELECTRIC ASS | 303 | | LS | TBL load forecast | 2002 | 68.64 | 54.98 | 70.21 | 71.16 | 75.96 | 53.82 | 49.52 | 54.97 | 66.01 | 79.41 | 94.00 | 77.88 | 68.05 |
| 27 | BENTON RURAL ELECTRIC ASS | 303 | | BASE | TBL load forecast | 2003 | 70.95 | 56.83 | 72.56 | 73.55 | 78.51 | 55.63 | 51.18 | 56.82 | 68.22 | 82.08 | 97.15 | 80.50 | 70.33 |
| 28 | BENTON RURAL ELECTRIC ASS | 303 | | LS | TBL load forecast | 2003 | 70.95 | 56.83 | 72.56 | 73.55 | 78.51 | 55.63 | 51.18 | 56.82 | 68.22 | 82.08 | 97.15 | 80.50 | 70.33 |
| 29 | BIG BEND ELECTRIC COOPERA | 306 | | BASE | TBL load forecast | 2002 | 51.80 | 33.60 | 37.40 | 40.20 | 38.30 | 30.40 | 51.40 | 77.80 | 106.50 | 93.70 | 99.20 | 81.60 | 61.83 |
| 30 | BIG BEND ELECTRIC COOPERA | 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 |
| 31 | BIG BEND ELECTRIC COOPERA | 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 |
| 32 | BIG BEND ELECTRIC COOPERA | 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 |
| 33 | BLACHLY-LANE COUNTY COOPE | 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 |
| 34 | BLACHLY-LANE COUNTY COOPE | 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 |
| 35 | BLACHLY-LANE COUNTY COOPE | 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 |
| 36 | BLACHLY-LANE COUNTY COOPE | 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 |
| 37 | 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 |
| 38 | 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 |
| 39 | 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 |
| 40 | 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 |
| 41 | BONNERS FERRY, CITY OF | 107 | | BASE | TBL load forecast | 2002 | 20.15 | 19.78 | 19.19 | 20.83 | 21.19 | 6.76 | 5.54 | 2.72 | 2.21 | 2.67 | 6.34 | 5.43 | 11.07 |
| 42 | BONNERS FERRY, CITY OF | 107 | | LS | TBL load forecast | 2002 | 22.17 | 23.12 | 23.88 | 24.52 | 24.28 | 8.50 | 7.35 | 7.10 | 7.52 | 7.18 | 8.55 | 10.60 | 14.56 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 43 | BONNERS FERRY, CITY OF | 107 | | BASE | TBL load forecast | 2003 | 20.26 | 19.91 | 19.31 | 20.84 | 21.26 | 6.78 | 5.57 | 2.75 | 2.23 | 2.69 | 6.34 | 5.44 | 11.12 |
| 44 | BONNERS FERRY, CITY OF | 107 | | LS | TBL load forecast | 2003 | 22.29 | 23.27 | 24.04 | 24.54 | 24.36 | 8.53 | 7.39 | 7.16 | 7.58 | 7.24 | 8.56 | 10.60 | 14.63 |
| 45 | 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 |
| 46 | 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 |
| 47 | 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 |
| 48 | 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 |
| 49 | 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 |
| 50 | 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 |
| 51 | 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 |
| 52 | 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 |
| 53 | CANBY, CITY OF, UTILITY B | 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 |
| 54 | CANBY, CITY OF, UTILITY B | 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 |
| 55 | CANBY, CITY OF, UTILITY B | 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 |
| 56 | CANBY, CITY OF, UTILITY B | 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 |
| 57 | 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 |
| 58 | 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 |
| 59 | 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 |
| 60 | 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 |
| 61 | CENTRAL ELECTRIC COOPERAT | 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 |
| 62 | CENTRAL ELECTRIC COOPERAT | 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 |
| 63 | CENTRAL ELECTRIC COOPERAT | 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 |
| 64 | CENTRAL ELECTRIC COOPERAT | 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 |
| 65 | 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 |
| 66 | 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 |
| 67 | 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 |
| 68 | 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 |
| 69 | CENTRAL MONTANA ELECTRIC | 313 | | BASE | OY99 NWPP Op Pgm | 2002 | 55.01 | 54.99 | 86.74 | 107.86 | 64.73 | 85.49 | 54.32 | 56.17 | 64.45 | 60.07 | 58.25 | 44.55 | 66.05 |
| 70 | CENTRAL MONTANA ELECTRIC | 313 | | LS | OY99 NWPP Op Pgm | 2002 | 96.56 | 115.64 | 171.11 | 189.65 | 147.52 | 155.49 | 120.63 | 95.29 | 114.00 | 110.40 | 109.92 | 80.95 | 125.60 |
| 71 | CENTRAL MONTANA ELECTRIC | 313 | | BASE | OY99 NWPP Op Pgm | 2003 | 55.55 | 55.75 | 87.87 | 108.00 | 65.21 | 85.99 | 55.00 | 56.97 | 65.38 | 61.07 | 58.32 | 44.57 | 66.64 |
| 72 | CENTRAL MONTANA ELECTRIC | 313 | | LS | OY99 NWPP Op Pgm | 2003 | 97.10 | 116.40 | 172.24 | 189.78 | 148.00 | 155.99 | 121.31 | 96.09 | 114.93 | 111.41 | 110.00 | 80.97 | 126.19 |
| 73 | 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 |
| 74 | 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 |
| 75 | 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 |
| 76 | 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 |
| 77 | CHENEY, CITY OF | 123 | | BASE | TBL load forecast | 2002 | 19.30 | 20.70 | 22.80 | 25.60 | 26.20 | 21.10 | 18.50 | 16.10 | 13.70 | 14.40 | 14.90 | 14.30 | 18.97 |
| 78 | 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 |
| 79 | 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 |
| 80 | 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 |
| 81 | 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 |
| 82 | 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 |
| 83 | 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 |
| 84 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 85 | 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 |
| 86 | 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 |
| 87 | 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 |
| 88 | 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 |
| 89 | CLARK COUNTY PUD NO 1 | 216 | PPL | BASE | 12/98 White Book | 2002 | 387.46 | 444.41 | 602.02 | 606.92 | 568.03 | 426.56 | 430.10 | 292.60 | 192.32 | 326.36 | 324.36 | 319.91 | 410.09 |
| 90 | CLARK COUNTY PUD NO 1 | 216 | PPL | LS | 12/98 White Book | 2002 | 619.63 | 707.96 | 804.75 | 806.26 | 840.87 | 599.14 | 498.01 | 491.51 | 355.16 | 347.37 | 423.40 | 444.29 | 578.20 |
| 91 | CLARK COUNTY PUD NO 1 | 216 | PPL | BASE | 12/98 White Book | 2003 | 397.17 | 454.21 | 612.20 | 617.33 | 582.11 | 435.50 | 437.72 | 300.76 | 198.23 | 331.90 | 330.96 | 327.14 | 418.77 |
| 92 | CLARK COUNTY PUD NO 1 | 216 | PPL | LS | 12/98 White Book | 2003 | 629.34 | 717.76 | 814.93 | 816.66 | 854.95 | 608.08 | 505.63 | 499.67 | 361.07 | 352.92 | 430.00 | 451.52 | 586.88 |
| 93 | 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 |
| 94 | 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 |
| 95 | 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 |
| 96 | 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 |
| 97 | COLUMBIA BASIN ELECTRIC C | 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 |
| 98 | COLUMBIA BASIN ELECTRIC C | 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 |
| 99 | COLUMBIA BASIN ELECTRIC C | 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 |
| 100 | COLUMBIA BASIN ELECTRIC C | 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 |
| 101 | COLUMBIA POWER COOPERATIV | 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 |
| 102 | COLUMBIA POWER COOPERATIV | 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 |
| 103 | COLUMBIA POWER COOPERATIV | 321 | | BASE | TBL load forecast | 2003 | 4.10 | 3.50 | 5.00 | 5.20 | 5.40 | 3.90 | 3.40 | 3.50 | 3.90 | 4.90 | 5.20 | 4.20 | 4.35 |
| 104 | COLUMBIA POWER COOPERATIV | 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 |
| 105 | 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 |
| 106 | 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 |
| 107 | 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 |
| 108 | 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 |
| 109 | COLUMBIA RURAL ELECTRIC A | 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 |
| 110 | COLUMBIA RURAL ELECTRIC A | 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 |
| 111 | COLUMBIA RURAL ELECTRIC A | 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 |
| 112 | COLUMBIA RURAL ELECTRIC A | 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 |
| 113 | CONSOLIDATED IRRIGATION D | 192 | | BASE | TBL load forecast | 2002 | 0.54 | 0.89 | 0.88 | 0.74 | 0.79 | 0.29 | 0.38 | 0.31 | 0.42 | 0.41 | 0.39 | 0.35 | 0.53 |
| 114 | CONSOLIDATED IRRIGATION D | 192 | | LS | TBL load forecast | 2002 | 1.01 | 1.42 | 0.96 | 1.30 | 1.16 | 0.47 | 0.55 | 0.51 | 0.58 | 0.67 | 0.64 | 0.59 | 0.82 |
| 115 | CONSOLIDATED IRRIGATION D | 192 | | BASE | TBL load forecast | 2003 | 0.54 | 0.89 | 0.88 | 0.74 | 0.79 | 0.29 | 0.38 | 0.31 | 0.42 | 0.42 | 0.39 | 0.35 | 0.53 |
| 116 | CONSOLIDATED IRRIGATION D | 192 | | LS | TBL load forecast | 2003 | 1.01 | 1.43 | 0.97 | 1.30 | 1.16 | 0.48 | 0.55 | 0.52 | 0.59 | 0.68 | 0.64 | 0.59 | 0.83 |
| 117 | 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 |
| 118 | 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 |
| 119 | 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 |
| 120 | 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 |
| 121 | COOS-CURRY ELECTRIC COOPE | 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 |
| 122 | COOS-CURRY ELECTRIC COOPE | 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 |
| 123 | COOS-CURRY ELECTRIC COOPE | 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 |
| 124 | COOS-CURRY ELECTRIC COOPE | 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 |
| 125 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 126 | 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 |
| 127 | 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 |
| 128 | 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 |
| 129 | COWLITZ COUNTY PUD NO 1 | 222 | | BASE | OY99 NWPP Op Pgm | 2002 | 425.47 | 460.74 | 473.11 | 481.63 | 466.62 | 458.60 | 416.58 | 364.40 | 428.40 | 353.11 | 364.91 | 417.39 | 425.91 |
| 130 | COWLITZ COUNTY PUD NO 1 | 222 | | LS | OY99 NWPP Op Pgm | 2002 | 499.47 | 534.74 | 547.11 | 555.63 | 540.62 | 532.60 | 490.58 | 438.40 | 502.40 | 427.11 | 438.91 | 491.39 | 499.91 |
| 131 | COWLITZ COUNTY PUD NO 1 | 222 | | BASE | OY99 NWPP Op Pgm | 2003 | 428.24 | 464.26 | 476.73 | 482.03 | 468.37 | 460.30 | 419.34 | 368.10 | 432.49 | 357.00 | 365.21 | 417.50 | 428.30 |
| 132 | COWLITZ COUNTY PUD NO 1 | 222 | | LS | OY99 NWPP Op Pgm | 2003 | 502.24 | 538.26 | 550.73 | 556.03 | 542.37 | 534.30 | 493.34 | 442.10 | 506.49 | 431.00 | 439.21 | 491.50 | 502.30 |
| 133 | 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 |
| 134 | DECLO, CITY OF | 127 | | LS | TBL load forecast | 2002 | 0.50 | 0.50 | 0.60 | 0.70 | 0.60 | 0.50 | 0.50 | 0.40 | 0.30 | 0.30 | 0.40 | 0.40 | 0.48 |
| 135 | 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 |
| 136 | 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 |
| 137 | DOUGLAS ELECTRIC COOPERAT | 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 |
| 138 | DOUGLAS ELECTRIC COOPERAT | 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 |
| 139 | DOUGLAS ELECTRIC COOPERAT | 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 |
| 140 | DOUGLAS ELECTRIC COOPERAT | 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 |
| 141 | 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 |
| 142 | DRAIN, CITY OF | 128 | | LS | TBL load forecast | 2002 | 4.10 | 4.00 | 4.80 | 5.00 | 5.10 | 4.30 | 4.00 | 3.50 | 3.10 | 3.20 | 3.20 | 3.20 | 3.96 |
| 143 | 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 |
| 144 | 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 |
| 145 | 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 |
| 146 | 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 |
| 147 | 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 |
| 148 | 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 |
| 149 | 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 |
| 150 | EATONVILLE, TOWN OF | 131 | | LS | TBL load forecast | 2002 | 4.90 | 5.40 | 6.40 | 6.80 | 6.60 | 4.40 | 4.00 | 3.60 | 2.50 | 2.30 | 2.30 | 3.40 | 4.38 |
| 151 | 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 |
| 152 | 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 |
| 153 | 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 |
| 154 | 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 |
| 155 | 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 |
| 156 | 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 |
| 157 | ELMHURST MUTUAL POWER & L | 334 | | BASE | TBL load forecast | 2002 | 46.60 | 48.10 | 58.00 | 61.40 | 65.20 | 49.90 | 40.00 | 29.40 | 21.90 | 20.40 | 22.70 | 23.20 | 40.57 |
| 158 | ELMHURST MUTUAL POWER & L | 334 | | LS | TBL load forecast | 2002 | 46.60 | 48.10 | 58.00 | 61.40 | 65.20 | 49.90 | 40.00 | 29.40 | 21.90 | 20.40 | 22.70 | 23.20 | 40.57 |
| 159 | ELMHURST MUTUAL POWER & L | 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 |
| 160 | ELMHURST MUTUAL POWER & L | 334 | | LS | TBL load forecast | 2003 | 47.50 | 49.00 | 59.10 | 62.60 | 66.40 | 50.80 | 40.80 | 30.00 | 22.30 | 20.80 | 23.10 | 23.70 | 41.34 |
| 161 | ENERGY NORTHWEST INC. | 841 | | BASE | recent tx bills | 2002 | 13.81 | 24.61 | 24.92 | 26.46 | 30.86 | 18.36 | 15.20 | 14.15 | 10.49 | 16.75 | 13.68 | 12.32 | 18.47 |
| 162 | ENERGY NORTHWEST INC. | 841 | | LS | recent tx bills | 2002 | 28.21 | 38.43 | 38.75 | 40.08 | 46.10 | 31.18 | 28.11 | 26.13 | 24.09 | 32.54 | 28.61 | 25.47 | 32.31 |
| 163 | ENERGY NORTHWEST INC. | 841 | | BASE | recent tx bills | 2003 | 13.89 | 24.77 | 25.09 | 26.47 | 30.96 | 18.42 | 15.29 | 14.27 | 10.57 | 16.90 | 13.69 | 12.32 | 18.55 |
| 164 | ENERGY NORTHWEST INC. | 841 | | LS | recent tx bills | 2003 | 28.36 | 38.68 | 39.00 | 40.11 | 46.25 | 31.28 | 28.27 | 26.35 | 24.29 | 32.84 | 28.63 | 25.48 | 32.46 |
| 165 | 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 |
| 166 | FALL RIVER RURAL ELECTRIC | 337 | | LS | TBL load forecast | 2002 | 25.00 | 28.30 | 36.10 | 34.60 | 34.90 | 26.30 | 20.80 | 20.90 | 36.70 | 43.30 | 35.10 | 21.10 | 30.26 |
| 167 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 168 | 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 |
| 169 | FARMERS ELECTRIC COOPERAT | 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 |
| 170 | FARMERS ELECTRIC COOPERAT | 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 |
| 171 | FARMERS ELECTRIC COOPERAT | 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 |
| 172 | FARMERS ELECTRIC COOPERAT | 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 |
| 173 | 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 |
| 174 | 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 |
| 175 | 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 |
| 176 | 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 |
| 177 | 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 |
| 178 | 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 |
| 179 | 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 |
| 180 | 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 |
| 181 | FLATHEAD ELECTRIC COOPERA | 339 | | BASE | modified BOS | 2002 | 72.35 | 77.94 | 78.03 | 92.08 | 125.23 | 89.52 | 62.36 | 63.82 | 61.58 | 66.69 | 68.52 | 56.80 | 76.24 |
| 182 | FLATHEAD ELECTRIC COOPERA | 339 | | LS | modified BOS | 2002 | 132.50 | 138.10 | 138.20 | 152.30 | 185.40 | 149.70 | 122.50 | 124.00 | 121.80 | 126.90 | 128.70 | 117.00 | 136.43 |
| 183 | FLATHEAD ELECTRIC COOPERA | 339 | | BASE | modified BOS | 2003 | 76.24 | 82.00 | 82.09 | 96.55 | 130.66 | 93.91 | 66.11 | 67.61 | 65.30 | 70.57 | 72.46 | 60.39 | 80.32 |
| 184 | FLATHEAD ELECTRIC COOPERA | 339 | | LS | modified BOS | 2003 | 136.41 | 142.17 | 142.26 | 156.72 | 190.83 | 154.08 | 126.11 | 127.61 | 125.30 | 130.57 | 132.46 | 120.39 | 140.41 |
| 185 | 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 |
| 186 | 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 |
| 187 | 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 |
| 188 | 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 |
| 189 | FRANKLIN COUNTY PUD NO 1 | 233 | | BASE | TBL load forecast | 2002 | 100.84 | 90.90 | 112.27 | 127.04 | 123.49 | 92.01 | 83.42 | 83.52 | 103.31 | 117.54 | 130.51 | 107.32 | 106.01 |
| 190 | FRANKLIN COUNTY PUD NO 1 | 233 | | LS | TBL load forecast | 2002 | 102.30 | 92.40 | 113.80 | 128.50 | 125.00 | 93.50 | 84.80 | 84.90 | 104.70 | 118.90 | 131.90 | 108.70 | 107.45 |
| 191 | FRANKLIN COUNTY PUD NO 1 | 233 | | BASE | TBL load forecast | 2003 | 103.47 | 93.29 | 115.18 | 130.30 | 126.66 | 94.43 | 86.80 | 86.90 | 107.17 | 121.75 | 135.03 | 111.28 | 109.36 |
| 192 | FRANKLIN COUNTY PUD NO 1 | 233 | | LS | TBL load forecast | 2003 | 104.80 | 94.60 | 116.50 | 131.60 | 128.00 | 95.80 | 86.80 | 86.90 | 107.20 | 121.80 | 135.00 | 111.30 | 110.03 |
| 193 | GLACIER ELECTRIC COOPERAT | 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 |
| 194 | GLACIER ELECTRIC COOPERAT | 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 |
| 195 | GLACIER ELECTRIC COOPERAT | 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 |
| 196 | GLACIER ELECTRIC COOPERAT | 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 |
| 197 | HARNEY ELECTRIC COOPERATI | 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 |
| 198 | HARNEY ELECTRIC COOPERATI | 341 | | LS | TBL load forecast | 2002 | 9.70 | 7.70 | 10.20 | 11.90 | 11.20 | 11.10 | 13.50 | 20.80 | 21.50 | 31.30 | 30.30 | 27.70 | 17.24 |
| 199 | HARNEY ELECTRIC COOPERATI | 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 |
| 200 | HARNEY ELECTRIC COOPERATI | 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 |
| 201 | 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 |
| 202 | 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 |
| 203 | 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 |
| 204 | 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 |
| 205 | HOOD RIVER ELECTRIC COOPE | 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 |
| 206 | HOOD RIVER ELECTRIC COOPE | 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 |
| 207 | HOOD RIVER ELECTRIC COOPE | 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 |
| 208 | HOOD RIVER ELECTRIC COOPE | 342 | | LS | TBL load forecast | 2003 | 19.50 | 19.70 | 20.30 | 21.90 | 21.80 | 18.30 | 16.20 | 12.20 | 9.80 | 9.60 | 13.10 | 15.70 | 16.51 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 209 | IDAHO COUNTY LIGHT & POWE | 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 |
| 210 | IDAHO COUNTY LIGHT & POWE | 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 |
| 211 | IDAHO COUNTY LIGHT & POWE | 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 |
| 212 | IDAHO COUNTY LIGHT & POWE | 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 |
| 213 | INLAND POWER & LIGHT COMP | 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 |
| 214 | INLAND POWER & LIGHT COMP | 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 |
| 215 | INLAND POWER & LIGHT COMP | 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 |
| 216 | INLAND POWER & LIGHT COMP | 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 |
| 217 | 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 |
| 218 | 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 |
| 219 | 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 |
| 220 | 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 |
| 221 | KOOTENAI ELECTRIC COOPERA | 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 |
| 222 | KOOTENAI ELECTRIC COOPERA | 351 | | LS | TBL load forecast | 2002 | 44.70 | 48.00 | 57.70 | 58.10 | 60.80 | 48.80 | 39.20 | 33.70 | 30.10 | 31.60 | 31.50 | 28.80 | 42.75 |
| 223 | KOOTENAI ELECTRIC COOPERA | 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 |
| 224 | KOOTENAI ELECTRIC COOPERA | 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 |
| 225 | 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 |
| 226 | 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 |
| 227 | 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 |
| 228 | 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 |
| 229 | LANE ELECTRIC COOPERATIVE | 354 | PNGC | BASE | TBL load forecast | 2002 | 44.00 | 44.10 | 58.80 | 58.20 | 64.40 | 50.90 | 39.80 | 29.40 | 21.70 | 22.00 | 22.90 | 21.20 | 39.78 |
| 230 | LANE ELECTRIC COOPERATIVE | 354 | PNGC | LS | TBL load forecast | 2002 | 44.70 | 44.90 | 59.50 | 58.90 | 65.20 | 51.70 | 40.40 | 30.00 | 22.30 | 22.60 | 23.50 | 21.80 | 40.46 |
| 231 | 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 |
| 232 | 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 |
| 233 | 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 |
| 234 | 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 |
| 235 | 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 |
| 236 | 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 |
| 237 | LINCOLN ELECTRIC COOPERAT | 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 |
| 238 | LINCOLN ELECTRIC COOPERAT | 357 | | LS | TBL load forecast | 2002 | 14.10 | 12.90 | 17.50 | 21.30 | 21.00 | 17.60 | 15.60 | 13.10 | 10.90 | 11.70 | 11.00 | 9.40 | 14.68 |
| 239 | LINCOLN ELECTRIC COOPERAT | 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 |
| 240 | LINCOLN ELECTRIC COOPERAT | 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 |
| 241 | LOST RIVER ELECTRIC COOPE | 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 |
| 242 | LOST RIVER ELECTRIC COOPE | 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 |
| 243 | LOST RIVER ELECTRIC COOPE | 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 |
| 244 | LOST RIVER ELECTRIC COOPE | 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 |
| 245 | LOWER VALLEY POWER & LIGH | 360 | | BASE | TBL load forecast | 2002 | 79.40 | 91.10 | 126.30 | 126.00 | 126.40 | 92.00 | 70.00 | 58.70 | 46.90 | 61.30 | 54.20 | 49.30 | 81.80 |
| 246 | LOWER VALLEY POWER & LIGH | 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 |
| 247 | LOWER VALLEY POWER & LIGH | 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 |
| 248 | LOWER VALLEY POWER & LIGH | 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 |
| 249 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 250 | 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 |
| 251 | 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 |
| 252 | 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 |
| 253 | MASON COUNTY PUD 3 | 258 | | BASE | TBL load forecast | 2002 | 104.64 | 104.37 | 130.94 | 134.31 | 139.43 | 115.62 | 95.50 | 79.27 | 62.07 | 64.67 | 62.54 | 62.50 | 96.32 |
| 254 | MASON COUNTY PUD 3 | 258 | | LS | TBL load forecast | 2002 | 104.60 | 104.40 | 130.90 | 134.30 | 139.40 | 115.60 | 95.50 | 79.30 | 62.10 | 64.70 | 62.50 | 62.50 | 96.32 |
| 255 | MASON COUNTY PUD 3 | 258 | | BASE | TBL load forecast | 2003 | 107.20 | 106.90 | 134.10 | 137.60 | 142.80 | 118.40 | 97.80 | 81.20 | 63.60 | 66.20 | 64.10 | 64.00 | 98.66 |
| 256 | MASON COUNTY PUD 3 | 258 | | LS | TBL load forecast | 2003 | 107.17 | 106.89 | 134.11 | 137.56 | 142.80 | 118.41 | 97.80 | 81.19 | 63.57 | 66.23 | 64.05 | 64.01 | 98.65 |
| 257 | 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 |
| 258 | 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 |
| 259 | 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 |
| 260 | 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 |
| 261 | 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 |
| 262 | MCMINNVILLE, CITY OF | 155 | | LS | TBL load forecast | 2002 | 121.70 | 134.00 | 137.80 | 134.50 | 160.40 | 114.90 | 119.80 | 112.00 | 104.70 | 100.40 | 90.60 | 83.90 | 117.89 |
| 263 | 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 |
| 264 | 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 |
| 265 | MIDSTATE ELECTRIC COOPERA | 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 |
| 266 | MIDSTATE ELECTRIC COOPERA | 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 |
| 267 | MIDSTATE ELECTRIC COOPERA | 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 |
| 268 | MIDSTATE ELECTRIC COOPERA | 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 |
| 269 | 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 |
| 270 | 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 |
| 271 | 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 |
| 272 | 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 |
| 273 | 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 |
| 274 | 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 |
| 275 | 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 |
| 276 | 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 |
| 277 | 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 |
| 278 | 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 |
| 279 | 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 |
| 280 | 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 |
| 281 | MISSOULA ELECTRIC COOPERA | 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 |
| 282 | MISSOULA ELECTRIC COOPERA | 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 |
| 283 | MISSOULA ELECTRIC COOPERA | 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 |
| 284 | MISSOULA ELECTRIC COOPERA | 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 |
| 285 | MODERN ELECTRIC WATER COM | 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 |
| 286 | MODERN ELECTRIC WATER COM | 366 | | LS | TBL load forecast | 2002 | 46.10 | 52.60 | 59.10 | 54.80 | 59.30 | 48.90 | 45.70 | 42.50 | 45.40 | 50.10 | 54.20 | 44.80 | 50.29 |
| 287 | MODERN ELECTRIC WATER COM | 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 |
| 288 | MODERN ELECTRIC WATER COM | 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 |
| 289 | 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 |
| 290 | 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 |
| 291 | 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 |

## 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 292 | 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 |
| 293 | 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 |
| 294 | 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 |
| 295 | 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 |
| 296 | 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 |
| 297 | 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 |
| 298 | 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 |
| 299 | 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 |
| 300 | 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 |
| 301 | 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 |
| 302 | 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 |
| 303 | 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 |
| 304 | 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 |
| 305 | 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 |
| 306 | 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 |
| 307 | 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 |
| 308 | 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 |
| 309 | 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 |
| 310 | OKANOGAN COUNTY ELECTRIC | 373 | | LS | TBL load forecast | 2002 | 7.20 | 7.40 | 9.50 | 10.90 | 10.40 | 7.10 | 5.70 | 4.90 | 4.10 | 4.60 | 5.00 | 4.50 | 6.77 |
| 311 | 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 |
| 312 | 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 |
| 313 | OKANOGAN COUNTY PUD NO 1 | 266 | | BASE | added 11 MW | 2002 | 44.31 | 7.81 | 32.15 | 68.51 | 57.52 | 27.44 | 23.23 | 0.00 | 0.00 | 6.07 | 26.69 | 18.37 | 26.01 |
| 314 | OKANOGAN COUNTY PUD NO 1 | 266 | | LS | added 11 MW | 2002 | 100.49 | 84.58 | 119.23 | 132.00 | 117.22 | 107.49 | 95.49 | 76.80 | 74.45 | 58.25 | 76.01 | 80.07 | 93.51 |
| 315 | OKANOGAN COUNTY PUD NO 1 | 266 | | BASE | added 11 MW | 2003 | 45.07 | 8.16 | 32.58 | 69.01 | 57.98 | 28.19 | 23.99 | 0.00 | 0.00 | 6.40 | 27.13 | 19.00 | 26.46 |
| 316 | OKANOGAN COUNTY PUD NO 1 | 266 | | LS | added 11 MW | 2003 | 101.24 | 84.93 | 119.66 | 132.50 | 117.68 | 108.24 | 96.24 | 77.22 | 75.08 | 58.58 | 76.45 | 80.70 | 94.04 |
| 317 | ORCAS POWER & LIGHT COOPE | 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 |
| 318 | ORCAS POWER & LIGHT COOPE | 376 | | LS | TBL load forecast | 2002 | 31.10 | 37.20 | 43.40 | 49.30 | 43.00 | 36.10 | 29.70 | 23.20 | 19.20 | 19.00 | 18.80 | 18.10 | 30.68 |
| 319 | ORCAS POWER & LIGHT COOPE | 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 |
| 320 | ORCAS POWER & LIGHT COOPE | 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 |
| 321 | 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 |
| 322 | 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 |
| 323 | 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 |
| 324 | 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 |
| 325 | PACIFIC COUNTY PUD NO 2 | 270 | | BASE | TBL load forecast | 2002 | 43.60 | 43.40 | 53.20 | 59.30 | 65.40 | 54.80 | 45.10 | 35.10 | 27.20 | 26.70 | 24.00 | 24.10 | 41.83 |
| 326 | PACIFIC COUNTY PUD NO 2 | 270 | | LS | TBL load forecast | 2002 | 43.60 | 43.40 | 53.20 | 59.30 | 65.40 | 54.80 | 45.10 | 35.10 | 27.20 | 26.70 | 24.00 | 24.10 | 41.83 |
| 327 | 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 |
| 328 | 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 |
| 329 | 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 |
| 330 | 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 |
| 331 | 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 |
| 332 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 333 | PEND OREILLE COUNTY PUD N | 273 | | BASE | OY99 NWPP Op Pgm | 2002 | 121.67 | 103.06 | 104.14 | 110.29 | 80.03 | 61.32 | 84.23 | 96.97 | 120.13 | 108.62 | 106.75 | 86.52 | 98.64 |
| 334 | PEND OREILLE COUNTY PUD N | 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 |
| 335 | PEND OREILLE COUNTY PUD N | 273 | | BASE | OY99 NWPP Op Pgm | 2003 | 122.34 | 103.74 | 104.83 | 110.37 | 80.29 | 61.52 | 84.70 | 97.80 | 121.11 | 109.61 | 106.82 | 86.54 | 99.14 |
| 336 | PEND OREILLE COUNTY PUD N | 273 | | LS | OY99 NWPP Op Pgm | 2003 | 122.60 | 104.00 | 105.10 | 110.70 | 80.60 | 61.90 | 85.10 | 98.20 | 121.50 | 109.90 | 107.10 | 86.80 | 99.46 |
| 337 | 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 |
| 338 | 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 |
| 339 | 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 |
| 340 | 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 |
| 341 | 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 |
| 342 | 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 |
| 343 | PLUMMER, CITY OF | 167 | | BASE | TBL load forecast | 2003 | 4.40 | 3.70 | 4.90 | 4.90 | 4.80 | 3.20 | 3.40 | 3.00 | 2.60 | 2.60 | 2.40 | 2.90 | 3.57 |
| 344 | 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 |
| 345 | PORT ANGELES, CITY OF, LI | 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 |
| 346 | PORT ANGELES, CITY OF, LI | 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 |
| 347 | PORT ANGELES, CITY OF, LI | 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 |
| 348 | PORT ANGELES, CITY OF, LI | 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 |
| 349 | PORT TOWNSEND PAPER CORPO | 716 | | BASE | 12/98 White Book | 2002 | 13.75 | 14.78 | 14.78 | 14.44 | 15.80 | 14.49 | 14.63 | 2.49 | 14.10 | 14.83 | 13.03 | 14.32 | 13.45 |
| 350 | PORT TOWNSEND PAPER CORPO | 716 | | LS | 12/98 White Book | 2002 | 13.75 | 14.78 | 14.78 | 14.44 | 15.80 | 14.49 | 14.63 | 2.49 | 14.10 | 14.83 | 13.03 | 14.32 | 13.45 |
| 351 | PORT TOWNSEND PAPER CORPO | 716 | | BASE | 12/98 White Book | 2003 | 13.83 | 14.88 | 14.88 | 14.45 | 15.85 | 14.54 | 14.71 | 2.51 | 14.21 | 14.97 | 13.04 | 14.32 | 13.52 |
| 352 | PORT TOWNSEND PAPER CORPO | 716 | | LS | 12/98 White Book | 2003 | 13.83 | 14.88 | 14.88 | 14.45 | 15.85 | 14.54 | 14.71 | 2.51 | 14.21 | 14.97 | 13.04 | 14.32 | 13.52 |
| 353 | 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 |
| 354 | RAFT RIVER RURAL ELECTRIC | 379 | PNGC | LS | TBL load forecast | 2002 | 8.80 | 6.90 | 7.80 | 9.60 | 7.90 | 6.90 | 10.90 | 30.50 | 35.10 | 48.30 | 38.00 | 39.10 | 20.82 |
| 355 | 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 |
| 356 | 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 |
| 357 | RAVALLI COUNTY ELECTRIC C | 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 |
| 358 | RAVALLI COUNTY ELECTRIC C | 380 | | LS | TBL load forecast | 2002 | 18.80 | 19.80 | 24.60 | 24.80 | 24.00 | 20.50 | 16.70 | 16.00 | 13.60 | 15.60 | 15.50 | 12.90 | 18.57 |
| 359 | RAVALLI COUNTY ELECTRIC C | 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 |
| 360 | RAVALLI COUNTY ELECTRIC C | 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 |
| 361 | RICHLAND, CITY OF | 175 | | BASE | TBL load forecast | 2002 | 85.41 | 74.47 | 106.64 | 130.80 | 128.27 | 82.01 | 65.47 | 64.31 | 71.12 | 80.69 | 89.11 | 64.26 | 86.88 |
| 362 | RICHLAND, CITY OF | 175 | | LS | TBL load forecast | 2002 | 102.76 | 91.82 | 123.99 | 148.15 | 145.62 | 99.36 | 82.68 | 81.52 | 88.33 | 97.90 | 106.32 | 81.47 | 104.16 |
| 363 | RICHLAND, CITY OF | 175 | | BASE | TBL load forecast | 2003 | 86.93 | 75.84 | 108.44 | 132.93 | 130.36 | 83.48 | 67.79 | 66.61 | 73.52 | 83.21 | 91.75 | 66.56 | 88.95 |
| 364 | RICHLAND, CITY OF | 175 | | LS | TBL load forecast | 2003 | 104.14 | 93.05 | 125.65 | 150.14 | 147.57 | 100.69 | 83.79 | 82.61 | 89.52 | 99.21 | 107.75 | 82.56 | 105.56 |
| 365 | RIVERSIDE ELECTRIC COMPAN | 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 |
| 366 | RIVERSIDE ELECTRIC COMPAN | 381 | | LS | TBL load forecast | 2002 | 2.50 | 2.40 | 3.60 | 2.20 | 1.90 | 1.70 | 1.40 | 1.60 | 1.90 | 2.30 | 1.90 | 1.60 | 2.08 |
| 367 | RIVERSIDE ELECTRIC COMPAN | 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 |
| 368 | RIVERSIDE ELECTRIC COMPAN | 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 |
| 369 | 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 |
| 370 | 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 |
| 371 | 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 |
| 372 | 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 |
| 373 | SALEM ELECTRIC COOPERATIV | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 374 | SALEM ELECTRIC COOPERATIV | 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 |
| 375 | SALEM ELECTRIC COOPERATIV | 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 |
| 376 | SALEM ELECTRIC COOPERATIV | 383 | | LS | TBL load forecast | 2003 | 62.50 | 64.10 | 78.20 | 74.50 | 80.80 | 62.30 | 56.10 | 48.70 | 48.10 | 53.00 | 57.70 | 54.30 | 61.69 |
| 377 | SALMON RIVER ELECTRIC COO | 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 |
| 378 | SALMON RIVER ELECTRIC COO | 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 |
| 379 | SALMON RIVER ELECTRIC COO | 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 |
| 380 | SALMON RIVER ELECTRIC COO | 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 |
| 381 | 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 |
| 382 | SKAMANIA COUNTY PUD NO 1 | 279 | | LS | TBL load forecast | 2002 | 20.60 | 18.10 | 25.20 | 27.20 | 29.10 | 23.80 | 20.00 | 16.30 | 12.20 | 13.30 | 13.30 | 13.00 | 19.34 |
| 383 | 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 |
| 384 | 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 |
| 385 | 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 |
| 386 | 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 |
| 387 | 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 |
| 388 | 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 |
| 389 | SOUTH SIDE ELECTRIC LINES | 385 | | BASE | TBL load forecast | 2002 | 4.50 | 4.90 | 5.80 | 6.10 | 6.00 | 4.70 | 4.90 | 8.20 | 10.80 | 10.00 | 7.40 | 7.30 | 6.72 |
| 390 | SOUTH SIDE ELECTRIC LINES | 385 | | LS | TBL load forecast | 2002 | 4.50 | 4.90 | 5.80 | 6.10 | 6.00 | 4.70 | 4.90 | 8.20 | 10.80 | 10.00 | 7.40 | 7.30 | 6.72 |
| 391 | 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 |
| 392 | 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 |
| 393 | 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 |
| 394 | 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 |
| 395 | 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 |
| 396 | 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 |
| 397 | SUMAS, CITY OF | 186 | | BASE | TBL load forecast | 2002 | 2.40 | 2.50 | 2.60 | 2.60 | 2.20 | 2.30 | 2.10 | 2.10 | 2.20 | 2.10 | 2.10 | 2.10 | 2.28 |
| 398 | SUMAS, CITY OF | 186 | | LS | TBL load forecast | 2002 | 2.40 | 2.50 | 2.60 | 2.60 | 2.20 | 2.30 | 2.10 | 2.10 | 2.20 | 2.10 | 2.10 | 2.10 | 2.28 |
| 399 | 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 |
| 400 | 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 |
| 401 | 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 |
| 402 | 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 |
| 403 | 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 |
| 404 | 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 |
| 405 | TANNER ELECTRIC COOPERATI | 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 |
| 406 | TANNER ELECTRIC COOPERATI | 387 | | LS | TBL load forecast | 2002 | 10.10 | 10.80 | 14.50 | 13.40 | 11.20 | 12.10 | 9.50 | 7.20 | 6.10 | 6.20 | 6.50 | 6.10 | 9.48 |
| 407 | TANNER ELECTRIC COOPERATI | 387 | | BASE | TBL load forecast | 2003 | 10.60 | 11.30 | 15.10 | 14.00 | 11.70 | 12.70 | 9.90 | 7.50 | 6.40 | 6.50 | 6.80 | 6.40 | 9.91 |
| 408 | TANNER ELECTRIC COOPERATI | 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 |
| 409 | 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 |
| 410 | 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 |
| 411 | 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 |
| 412 | 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 |
| 413 | 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 |
| 414 | 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 |
| 415 | 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 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 416 | 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 |
| 417 | 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 |
| 418 | 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 |
| 419 | 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 |
| 420 | 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 |
| 421 | 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 |
| 422 | U.S. DEPARTMENT OF NAVY ( | 451 | | LS | TBL load forecast | 2002 | 31.00 | 32.10 | 30.10 | 38.70 | 32.60 | 31.90 | 32.30 | 30.60 | 29.50 | 29.40 | 31.40 | 29.50 | 31.59 |
| 423 | 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 |
| 424 | U.S. DEPARTMENT OF NAVY ( | 451 | | LS | TBL load forecast | 2003 | 31.50 | 32.60 | 30.60 | 39.30 | 33.00 | 32.40 | 32.70 | 31.00 | 29.90 | 29.90 | 31.80 | 29.90 | 32.05 |
| 425 | 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 |
| 426 | U.S. DEPARTMENT OF NAVY ( | 490 | | LS | TBL load forecast | 2002 | 24.70 | 25.70 | 25.50 | 27.50 | 30.00 | 26.20 | 25.30 | 23.30 | 22.50 | 21.90 | 17.40 | 20.70 | 24.23 |
| 427 | 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 |
| 428 | U.S. DEPARTMENT OF NAVY ( | 490 | | LS | TBL load forecast | 2003 | 24.90 | 26.00 | 25.80 | 27.80 | 30.40 | 26.50 | 25.60 | 23.50 | 22.70 | 22.10 | 17.60 | 20.90 | 24.48 |
| 429 | 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 |
| 430 | U.S. DEPARTMENT OF NAVY ( | 491 | | LS | TBL load forecast | 2002 | 1.60 | 1.50 | 1.80 | 1.60 | 1.70 | 1.50 | 1.70 | 1.60 | 1.50 | 1.60 | 1.50 | 1.60 | 1.60 |
| 431 | 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 |
| 432 | U.S. DEPARTMENT OF NAVY ( | 491 | | LS | TBL load forecast | 2003 | 1.60 | 1.60 | 1.80 | 1.70 | 1.70 | 1.50 | 1.70 | 1.60 | 1.60 | 1.60 | 1.50 | 1.60 | 1.63 |
| 433 | 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 |
| 434 | UMATILLA ELECTRIC COOPERA | 388 | PNGC | LS | TBL load forecast | 2002 | 91.90 | 104.60 | 126.70 | 103.20 | 79.90 | 89.10 | 80.80 | 130.00 | 140.60 | 151.90 | 162.10 | 122.50 | 115.28 |
| 435 | 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 |
| 436 | UMATILLA ELECTRIC COOPERA | 388 | PNGC | LS | TBL load forecast | 2003 | 93.90 | 106.90 | 129.40 | 105.40 | 81.60 | 91.00 | 82.50 | 132.80 | 143.60 | 155.20 | 165.60 | 125.10 | 117.75 |
| 437 | 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 |
| 438 | UNITED ELECTRIC COOP | 311 | | LS | TBL load forecast | 2002 | 24.50 | 22.70 | 31.50 | 32.20 | 31.10 | 24.30 | 21.00 | 22.20 | 27.20 | 33.60 | 28.50 | 27.70 | 27.21 |
| 439 | 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 |
| 440 | UNITED ELECTRIC COOP | 311 | | LS | TBL load forecast | 2003 | 25.40 | 23.50 | 32.70 | 33.40 | 32.20 | 25.20 | 21.80 | 23.10 | 28.20 | 34.90 | 29.50 | 28.70 | 28.22 |
| 441 | 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 |
| 442 | US BUREAU OF MINES | 410 | | LS | TBL load forecast | 2002 | 0.70 | 0.60 | 0.90 | 1.10 | 1.10 | 0.80 | 0.70 | 0.50 | 0.30 | 0.40 | 0.30 | 0.30 | 0.64 |
| 443 | 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 |
| 444 | US BUREAU OF MINES | 410 | | LS | TBL load forecast | 2003 | 0.70 | 0.60 | 0.90 | 1.20 | 1.10 | 0.80 | 0.70 | 0.50 | 0.30 | 0.40 | 0.30 | 0.30 | 0.65 |
| 445 | US DEPT OF ENERGY (300 AR | 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 |
| 446 | US DEPT OF ENERGY (300 AR | 405 | | LS | TBL load forecast | 2002 | 35.40 | 35.00 | 42.20 | 44.40 | 42.80 | 37.60 | 35.50 | 31.20 | 30.30 | 36.40 | 39.10 | 36.60 | 37.21 |
| 447 | US DEPT OF ENERGY (300 AR | 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 |
| 448 | US DEPT OF ENERGY (300 AR | 405 | | LS | TBL load forecast | 2003 | 35.50 | 35.10 | 42.40 | 44.70 | 43.00 | 37.80 | 35.70 | 31.30 | 30.50 | 36.60 | 39.30 | 36.80 | 37.39 |
| 449 | US DEPT OF ENERGY (RICHLA | 404 | | BASE | TBL load forecast | 2002 | 60.33 | 64.60 | 67.00 | 78.44 | 72.37 | 29.45 | 29.82 | 27.18 | -4.36 | 40.81 | 36.64 | 28.24 | 44.21 |
| 450 | US DEPT OF ENERGY (RICHLA | 404 | | LS | TBL load forecast | 2002 | 71.20 | 75.00 | 83.70 | 84.20 | 85.40 | 32.30 | 40.00 | 46.80 | 32.10 | 37.30 | 2.40 | 31.30 | 51.81 |
| 451 | US DEPT OF ENERGY (RICHLA | 404 | | BASE | TBL load forecast | 2003 | 60.66 | 65.03 | 67.44 | 78.50 | 72.60 | 29.55 | 29.99 | 27.41 | -4.39 | 41.18 | 36.66 | 28.25 | 44.41 |
| 452 | US DEPT OF ENERGY (RICHLA | 404 | | LS | TBL load forecast | 2003 | 71.60 | 75.50 | 84.20 | 84.20 | 85.70 | 32.40 | 40.20 | 47.20 | 32.40 | 37.70 | 2.40 | 31.30 | 52.07 |
| 453 | USBIA-MISSION VALLEY POWE | 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 |
| 454 | USBIA-MISSION VALLEY POWE | 483 | | LS | TBL load forecast | 2002 | 40.70 | 47.60 | 57.40 | 59.00 | 59.10 | 48.50 | 42.60 | 40.60 | 34.40 | 38.20 | 40.40 | 36.60 | 45.43 |
| 455 | USBIA-MISSION VALLEY POWE | 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 |
| 456 | USBIA-MISSION VALLEY POWE | 483 | | LS | TBL load forecast | 2003 | 41.20 | 48.20 | 58.10 | 59.70 | 59.80 | 49.10 | 43.20 | 41.10 | 34.80 | 38.70 | 40.90 | 37.10 | 45.99 |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 457 | USBR, YAKIMA PROJECT (ROZ | 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 |
| 458 | USBR, YAKIMA PROJECT (ROZ | 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 |
| 459 | USBR, YAKIMA PROJECT (ROZ | 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 |
| 460 | USBR, YAKIMA PROJECT (ROZ | 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 |
| 461 | 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 |
| 462 | 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 |
| 463 | 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 |
| 464 | 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 |
| 465 | 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 |
| 466 | 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 |
| 467 | 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 |
| 468 | 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 |
| 469 | 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 |
| 470 | WAHKIAKUM COUNTY PUD NO 1 | 293 | | LS | TBL load forecast | 2002 | 7.00 | 7.70 | 9.40 | 9.90 | 10.00 | 8.30 | 6.80 | 5.20 | 4.10 | 3.90 | 3.70 | 3.90 | 6.66 |
| 471 | 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 |
| 472 | WAHKIAKUM COUNTY PUD NO 1 | 293 | | LS | TBL load forecast | 2003 | 7.20 | 7.90 | 9.60 | 10.10 | 10.20 | 8.50 | 6.90 | 5.30 | 4.10 | 3.90 | 3.80 | 3.90 | 6.78 |
| 473 | WASCO ELECTRIC COOPERATIV | 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 |
| 474 | WASCO ELECTRIC COOPERATIV | 394 | | LS | TBL load forecast | 2002 | 13.30 | 12.50 | 16.30 | 15.90 | 15.60 | 13.10 | 10.90 | 10.20 | 9.10 | 11.40 | 11.70 | 10.10 | 12.51 |
| 475 | WASCO ELECTRIC COOPERATIV | 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 |
| 476 | WASCO ELECTRIC COOPERATIV | 394 | | LS | TBL load forecast | 2003 | 13.40 | 12.60 | 16.40 | 16.00 | 15.70 | 13.20 | 11.00 | 10.30 | 9.10 | 11.50 | 11.80 | 10.20 | 12.60 |
| 477 | WASHINGTON PUBLIC POWER S | 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 |
| 478 | WASHINGTON PUBLIC POWER S | 195 | | LS | TBL load forecast | 2002 | 4.40 | 3.90 | 5.40 | 5.50 | 5.30 | 4.30 | 4.00 | 3.30 | 3.10 | 3.80 | 3.80 | 3.60 | 4.20 |
| 479 | WASHINGTON PUBLIC POWER S | 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 |
| 480 | WASHINGTON PUBLIC POWER S | 195 | | LS | TBL load forecast | 2003 | 4.40 | 4.00 | 5.50 | 5.50 | 5.30 | 4.30 | 4.00 | 3.30 | 3.10 | 3.80 | 3.90 | 3.60 | 4.23 |
| 481 | 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 |
| 482 | WELLS RURAL ELECTRIC COOP | 396 | | LS | TBL load forecast | 2002 | 85.50 | 88.40 | 86.00 | 88.50 | 93.40 | 76.20 | 81.90 | 90.80 | 79.50 | 77.20 | 79.80 | 88.00 | 84.60 |
| 483 | 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 |
| 484 | WELLS RURAL ELECTRIC COOP | 396 | | LS | TBL load forecast | 2003 | 86.00 | 88.80 | 86.50 | 89.00 | 93.90 | 76.60 | 82.30 | 91.30 | 79.90 | 77.60 | 80.20 | 88.40 | 85.04 |
| 485 | 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 |
| 486 | WEST OREGON ELECTRIC COOP | 397 | | LS | TBL load forecast | 2002 | 13.90 | 18.40 | 19.00 | 19.70 | 18.00 | 13.80 | 14.40 | 10.60 | 8.50 | 9.50 | 9.40 | 10.00 | 13.77 |
| 487 | 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 |
| 488 | WEST OREGON ELECTRIC COOP | 397 | | LS | TBL load forecast | 2003 | 14.20 | 18.80 | 19.40 | 20.10 | 18.40 | 14.10 | 14.70 | 10.80 | 8.70 | 9.70 | 9.60 | 10.30 | 14.07 |
| 489 | WHATCOM COUNTY PUD NO 1 | 298 | | BASE | TBL load forecast | 2002 | 73.26 | 60.81 | 73.92 | 71.56 | 75.31 | 56.60 | 62.87 | 73.79 | 63.21 | 73.22 | 64.99 | 74.43 | 68.66 |
| 490 | WHATCOM COUNTY PUD NO 1 | 298 | | LS | TBL load forecast | 2002 | 73.30 | 60.80 | 73.90 | 71.60 | 75.30 | 56.60 | 62.90 | 73.80 | 63.20 | 73.20 | 65.00 | 74.40 | 68.67 |
| 491 | WHATCOM COUNTY PUD NO 1 | 298 | | BASE | TBL load forecast | 2003 | 63.50 | 61.02 | 74.16 | 71.88 | 75.56 | 56.77 | 63.10 | 74.03 | 63.44 | 73.46 | 65.25 | 74.68 | 68.07 |
| 492 | WHATCOM COUNTY PUD NO 1 | 298 | | LS | TBL load forecast | 2003 | 63.50 | 61.00 | 74.20 | 71.90 | 75.60 | 56.80 | 63.10 | 74.00 | 63.40 | 73.50 | 65.30 | 74.70 | 68.08 |

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 | Utility Delivery Billing Determinant | | | | | 645.1 |

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 1a. Entities excluded from this analysis are shown in Table 1b, 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 1a
## Scope of Forecast
## Customers Included in Forecast

| | Name | No. |
|---|---|---|
| 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 |
| 48 | Glacier Electric Coop. Inc. | 340 |

# Appendix D, Table 1a
## Scope of Forecast
## Customers Included in Forecast

| | Name | No. |
|---|---|---|
| 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 1a
## Scope of Forecast
## Customers Included in Forecast

| | 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 1b
## Scope of Forecast
## Excluded Customers

| | Name | No. |
|---|---|---|
| 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

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Asotin County PUD | 201 | 1998 | 10 | NT | TRUE | 0.080 | 0.080 | 0.076 | 0.076 | 0.000 | 0.000 | 0.156 | 0.156 |
| Asotin County PUD | 201 | 1998 | 11 | NT | TRUE | 0.083 | 0.083 | 0.079 | 0.079 | 0.000 | 0.000 | 0.086 | 0.086 |
| Asotin County PUD | 201 | 1998 | 12 | NT | TRUE | 0.003 | 0.003 | 0.003 | 0.003 | 0.000 | 0.000 | 0.058 | 0.058 |
| Asotin County PUD | 201 | 1999 | 1 | NT | TRUE | 0.002 | 0.002 | 0.002 | 0.002 | 0.000 | 0.000 | 0.004 | 0.004 |
| Asotin County PUD | 201 | 1999 | 2 | NT | TRUE | 0.001 | 0.001 | 0.002 | 0.002 | 0.000 | 0.000 | 0.037 | 0.037 |
| Asotin County PUD | 201 | 1999 | 3 | NT | TRUE | 0.082 | 0.082 | 0.001 | 0.001 | 0.000 | 0.000 | 0.082 | 0.082 |
| Asotin County PUD | 201 | 1999 | 4 | NT | TRUE | 0.099 | 0.099 | 0.095 | 0.095 | 0.000 | 0.000 | 0.099 | 0.099 |
| Asotin County PUD | 201 | 1999 | 5 | NT | TRUE | 0.101 | 0.101 | 0.127 | 0.127 | 0.000 | 0.000 | 0.101 | 0.101 |
| Asotin County PUD | 201 | 1999 | 6 | NT | TRUE | 0.082 | 0.082 | 0.458 | 0.458 | 0.000 | 0.000 | 0.082 | 0.082 |
| Asotin County PUD | 201 | 1999 | 7 | NT | TRUE | 0.837 | 0.837 | 0.689 | 0.689 | 0.000 | 0.000 | 0.837 | 0.837 |
| Asotin County PUD | 201 | 1999 | 8 | NT | TRUE | 0.816 | 0.816 | 1.333 | 1.333 | 0.000 | 0.000 | 0.816 | 0.816 |
| Asotin County PUD | 201 | 1999 | 9 | NT | TRUE | 0.816 | 0.816 | 1.482 | 1.482 | 0.000 | 0.000 | 0.816 | 0.816 |
| Asotin County PUD | 201 | 1999 | 10 | NT | TRUE | 0.241 | 0.241 | 0.080 | 0.080 | 0.000 | 0.000 | 0.165 | 0.165 |
| Asotin County PUD | 201 | 1999 | 11 | NT | TRUE | 0.095 | 0.095 | 0.084 | 0.084 | 0.000 | 0.000 | 0.092 | 0.092 |
| Asotin County PUD | 201 | 1999 | 12 | NT | TRUE | 0.113 | 0.113 | 0.003 | 0.003 | 0.000 | 0.000 | 0.058 | 0.058 |
| Asotin County PUD | 201 | 2000 | 1 | NT | TRUE | 0.005 | 0.005 | 0.002 | 0.002 | 0.000 | 0.000 | 0.004 | 0.004 |
| Asotin County PUD | 201 | 2000 | 2 | NT | TRUE | 0.072 | 0.072 | 0.002 | 0.002 | 0.000 | 0.000 | 0.037 | 0.037 |
| Asotin County PUD | 201 | 2000 | 3 | NT | FALSE | | | 0.001 | 0.001 | 0.000 | 0.000 | 0.082 | 0.082 |
| Asotin County PUD | 201 | 2000 | 4 | NT | FALSE | | | 0.091 | 0.091 | 0.000 | 0.000 | 0.095 | 0.095 |
| Asotin County PUD | 201 | 2000 | 5 | NT | FALSE | | | 0.111 | 0.111 | 0.000 | 0.000 | 0.088 | 0.088 |
| Asotin County PUD | 201 | 2000 | 6 | NT | FALSE | | | 0.462 | 0.462 | 0.000 | 0.000 | 0.083 | 0.083 |
| Asotin County PUD | 201 | 2000 | 7 | NT | FALSE | | | 0.696 | 0.696 | 0.000 | 0.000 | 0.846 | 0.846 |
| Asotin County PUD | 201 | 2000 | 8 | NT | FALSE | | | 1.293 | 1.293 | 0.000 | 0.000 | 0.792 | 0.792 |
| Asotin County PUD | 201 | 2000 | 9 | NT | FALSE | | | 1.412 | 1.412 | 0.000 | 0.000 | 0.777 | 0.777 |
| Asotin County PUD | 201 | 2000 | 10 | NT | FALSE | | | 0.081 | 0.081 | 0.000 | 0.000 | 0.167 | 0.167 |
| Asotin County PUD | 201 | 2000 | 11 | NT | FALSE | | | 0.084 | 0.084 | 0.000 | 0.000 | 0.092 | 0.092 |
| Asotin County PUD | 201 | 2000 | 12 | NT | FALSE | | | 0.003 | 0.003 | 0.000 | 0.000 | 0.058 | 0.058 |
| Asotin County PUD | 201 | 2001 | 1 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.004 | 0.004 |
| Asotin County PUD | 201 | 2001 | 2 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.037 | 0.037 |
| Asotin County PUD | 201 | 2001 | 3 | NT | FALSE | | | 0.001 | 0.001 | 0.000 | 0.000 | 0.082 | 0.082 |
| Asotin County PUD | 201 | 2001 | 4 | NT | FALSE | | | 0.083 | 0.083 | 0.000 | 0.000 | 0.086 | 0.086 |
| Asotin County PUD | 201 | 2001 | 5 | NT | FALSE | | | 0.104 | 0.104 | 0.000 | 0.000 | 0.083 | 0.083 |
| Asotin County PUD | 201 | 2001 | 6 | NT | FALSE | | | 0.423 | 0.423 | 0.000 | 0.000 | 0.076 | 0.076 |
| Asotin County PUD | 201 | 2001 | 7 | NT | FALSE | | | 0.739 | 0.739 | 0.000 | 0.000 | 0.898 | 0.898 |
| Asotin County PUD | 201 | 2001 | 8 | NT | FALSE | | | 1.362 | 1.362 | 0.000 | 0.000 | 0.834 | 0.834 |
| Asotin County PUD | 201 | 2001 | 9 | NT | FALSE | | | 1.412 | 1.412 | 0.000 | 0.000 | 0.777 | 0.777 |
| Asotin County PUD | 201 | 2001 | 10 | NT | FALSE | | | 0.081 | 0.081 | 0.000 | 0.000 | 0.081 | 0.081 |
| Asotin County PUD | 201 | 2001 | 11 | NT | FALSE | | | 0.085 | 0.085 | 0.000 | 0.000 | 0.085 | 0.085 |
| Asotin County PUD | 201 | 2001 | 12 | NT | FALSE | | | 0.003 | 0.003 | 0.000 | 0.000 | 0.003 | 0.003 |
| Asotin County PUD | 201 | 2002 | 1 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.002 | 0.002 |
| Asotin County PUD | 201 | 2002 | 2 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.002 | 0.002 |
| Asotin County PUD | 201 | 2002 | 3 | NT | FALSE | | | 0.001 | 0.001 | 0.000 | 0.000 | 0.001 | 0.001 |
| Asotin County PUD | 201 | 2002 | 4 | NT | FALSE | | | 0.084 | 0.084 | 0.000 | 0.000 | 0.084 | 0.084 |
| Asotin County PUD | 201 | 2002 | 5 | NT | FALSE | | | 0.104 | 0.104 | 0.000 | 0.000 | 0.104 | 0.104 |
| Asotin County PUD | 201 | 2002 | 6 | NT | FALSE | | | 0.427 | 0.427 | 0.000 | 0.000 | 0.427 | 0.427 |
| Asotin County PUD | 201 | 2002 | 7 | NT | FALSE | | | 0.746 | 0.746 | 0.000 | 0.000 | 0.746 | 0.746 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Asotin County PUD | 201 | 2002 | 8 | NT | FALSE | | | 1.363 | 1.363 | 0.000 | 0.000 | 1.363 | 1.363 |
| Asotin County PUD | 201 | 2002 | 9 | NT | FALSE | | | 1.412 | 1.412 | 0.000 | 0.000 | 1.412 | 1.412 |
| Asotin County PUD | 201 | 2002 | 10 | NT | FALSE | | | 0.082 | 0.082 | 0.000 | 0.000 | 0.082 | 0.082 |
| Asotin County PUD | 201 | 2002 | 11 | NT | FALSE | | | 0.085 | 0.085 | 0.000 | 0.000 | 0.085 | 0.085 |
| Asotin County PUD | 201 | 2002 | 12 | NT | FALSE | | | 0.003 | 0.003 | 0.000 | 0.000 | 0.003 | 0.003 |
| Asotin County PUD | 201 | 2003 | 1 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.002 | 0.002 |
| Asotin County PUD | 201 | 2003 | 2 | NT | FALSE | | | 0.002 | 0.002 | 0.000 | 0.000 | 0.002 | 0.002 |
| Asotin County PUD | 201 | 2003 | 3 | NT | FALSE | | | 0.001 | 0.001 | 0.000 | 0.000 | 0.001 | 0.001 |
| Asotin County PUD | 201 | 2003 | 4 | NT | FALSE | | | 0.084 | 0.084 | 0.000 | 0.000 | 0.084 | 0.084 |
| Asotin County PUD | 201 | 2003 | 5 | NT | FALSE | | | 0.105 | 0.105 | 0.000 | 0.000 | 0.105 | 0.105 |
| Asotin County PUD | 201 | 2003 | 6 | NT | FALSE | | | 0.430 | 0.430 | 0.000 | 0.000 | 0.430 | 0.430 |
| Asotin County PUD | 201 | 2003 | 7 | NT | FALSE | | | 0.752 | 0.752 | 0.000 | 0.000 | 0.752 | 0.752 |
| Asotin County PUD | 201 | 2003 | 8 | NT | FALSE | | | 1.364 | 1.364 | 0.000 | 0.000 | 1.364 | 1.364 |
| Asotin County PUD | 201 | 2003 | 9 | NT | FALSE | | | 1.412 | 1.412 | 0.000 | 0.000 | 1.412 | 1.412 |
| Bonners Ferry, City of | 107 | 1998 | 10 | NTP | TRUE | 10.311 | 10.311 | | | | | | |
| Bonners Ferry, City of | 107 | 1998 | 11 | NTP | TRUE | 9.951 | 11.031 | | | | | | |
| Bonners Ferry, City of | 107 | 1998 | 12 | NTP | TRUE | 12.579 | 13.669 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 1 | NTP | TRUE | 10.770 | 11.001 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 2 | NTP | TRUE | 8.761 | 10.810 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 3 | NTP | TRUE | 7.701 | 9.681 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 4 | NTP | TRUE | 7.731 | 8.311 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 5 | NTP | TRUE | 7.381 | 8.653 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 6 | NTP | TRUE | 5.353 | 8.073 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 7 | NTP | TRUE | 5.523 | 6.633 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 8 | NTP | TRUE | 6.673 | 8.362 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 9 | NTP | TRUE | 8.233 | 11.121 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 10 | NTP | TRUE | 8.592 | 11.011 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 11 | NTP | TRUE | 10.061 | 11.131 | | | | | | |
| Bonners Ferry, City of | 107 | 1999 | 12 | NTP | TRUE | 8.891 | 11.060 | | | | | | |
| Bonners Ferry, City of | 107 | 2000 | 1 | NTP | TRUE | 10.150 | 12.900 | | | | | | |
| Bonners Ferry, City of | 107 | 2000 | 2 | NTP | TRUE | 11.560 | 11.751 | | | | | | |
| Bonners Ferry, City of | 107 | 2000 | 3 | NTP | FALSE | | | 8.445 | 8.445 | 0.000 | | 6.718 | 8.445 |
| Bonners Ferry, City of | 107 | 2000 | 4 | NTP | FALSE | | | 7.268 | 5.885 | 0.000 | | 5.474 | 7.268 |
| Bonners Ferry, City of | 107 | 2000 | 5 | NTP | FALSE | | | 6.981 | 3.139 | 0.000 | | 2.678 | 6.981 |
| Bonners Ferry, City of | 107 | 2000 | 6 | NTP | FALSE | | | 7.399 | 3.280 | 0.000 | | 2.175 | 7.399 |
| Bonners Ferry, City of | 107 | 2000 | 7 | NTP | FALSE | | | 7.046 | 3.147 | 0.000 | | 2.621 | 7.046 |
| Bonners Ferry, City of | 107 | 2000 | 8 | NTP | FALSE | | | 8.539 | 7.928 | 0.000 | | 6.327 | 8.539 |
| Bonners Ferry, City of | 107 | 2000 | 9 | NTP | FALSE | | | 10.594 | 7.336 | 0.000 | | 5.431 | 10.594 |
| Bonners Ferry, City of | 107 | 2000 | 10 | NTP | FALSE | | | 22.047 | 22.528 | 0.000 | | 20.036 | 22.047 |
| Bonners Ferry, City of | 107 | 2000 | 11 | NTP | FALSE | | | 22.967 | 21.757 | 0.000 | | 19.646 | 22.967 |
| Bonners Ferry, City of | 107 | 2000 | 12 | NTP | FALSE | | | 23.720 | 22.021 | 0.000 | | 19.059 | 23.720 |
| Bonners Ferry, City of | 107 | 2001 | 1 | NTP | FALSE | | | 24.506 | 23.710 | 0.000 | | 20.811 | 24.506 |
| Bonners Ferry, City of | 107 | 2001 | 2 | NTP | FALSE | | | 24.204 | 23.355 | 0.000 | | 21.122 | 24.204 |
| Bonners Ferry, City of | 107 | 2001 | 3 | NTP | FALSE | | | 8.472 | 8.472 | 0.000 | | 6.740 | 8.472 |
| Bonners Ferry, City of | 107 | 2001 | 4 | NTP | FALSE | | | 7.309 | 5.918 | 0.000 | | 5.505 | 7.309 |
| Bonners Ferry, City of | 107 | 2001 | 5 | NTP | FALSE | | | 7.040 | 3.166 | 0.000 | | 2.700 | 7.040 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Bonners Ferry, City of | 107 | 2001 | 6 | NTP | FALSE | | | 7.459 | 3.307 | 0.000 | | 2.193 | 7.459 |
| Bonners Ferry, City of | 107 | 2001 | 7 | NTP | FALSE | | | 7.110 | 3.176 | 0.000 | | 2.644 | 7.110 |
| Bonners Ferry, City of | 107 | 2001 | 8 | NTP | FALSE | | | 8.544 | 7.933 | 0.000 | | 6.331 | 8.544 |
| Bonners Ferry, City of | 107 | 2001 | 9 | NTP | FALSE | | | 10.596 | 7.338 | 0.000 | | 5.432 | 10.596 |
| Bonners Ferry, City of | 107 | 2001 | 10 | NT | FALSE | | | 22.169 | 22.653 | 0.000 | | 20.147 | 22.169 |
| Bonners Ferry, City of | 107 | 2001 | 11 | NT | FALSE | | | 23.118 | 21.900 | 0.000 | | 19.775 | 23.118 |
| Bonners Ferry, City of | 107 | 2001 | 12 | NT | FALSE | | | 23.877 | 22.167 | 0.000 | | 19.185 | 23.877 |
| Bonners Ferry, City of | 107 | 2002 | 1 | NT | FALSE | | | 24.523 | 23.727 | 0.000 | | 20.826 | 24.523 |
| Bonners Ferry, City of | 107 | 2002 | 2 | NT | FALSE | | | 24.283 | 23.431 | 0.000 | | 21.191 | 24.283 |
| Bonners Ferry, City of | 107 | 2002 | 3 | NT | FALSE | | | 8.500 | 8.500 | 0.000 | | 6.761 | 8.500 |
| Bonners Ferry, City of | 107 | 2002 | 4 | NT | FALSE | | | 7.350 | 5.951 | 0.000 | | 5.536 | 7.350 |
| Bonners Ferry, City of | 107 | 2002 | 5 | NT | FALSE | | | 7.099 | 3.192 | 0.000 | | 2.723 | 7.099 |
| Bonners Ferry, City of | 107 | 2002 | 6 | NT | FALSE | | | 7.520 | 3.333 | 0.000 | | 2.210 | 7.520 |
| Bonners Ferry, City of | 107 | 2002 | 7 | NT | FALSE | | | 7.175 | 3.205 | 0.000 | | 2.669 | 7.175 |
| Bonners Ferry, City of | 107 | 2002 | 8 | NT | FALSE | | | 8.550 | 7.939 | 0.000 | | 6.335 | 8.550 |
| Bonners Ferry, City of | 107 | 2002 | 9 | NT | FALSE | | | 10.598 | 7.339 | 0.000 | | 5.433 | 10.598 |
| Bonners Ferry, City of | 107 | 2002 | 10 | NT | FALSE | | | 22.292 | 22.779 | 0.000 | | 20.259 | 22.292 |
| Bonners Ferry, City of | 107 | 2002 | 11 | NT | FALSE | | | 23.270 | 22.044 | 0.000 | | 19.905 | 23.270 |
| Bonners Ferry, City of | 107 | 2002 | 12 | NT | FALSE | | | 24.035 | 22.314 | 0.000 | | 19.312 | 24.035 |
| Bonners Ferry, City of | 107 | 2003 | 1 | NT | FALSE | | | 24.540 | 23.744 | 0.000 | | 20.840 | 24.540 |
| Bonners Ferry, City of | 107 | 2003 | 2 | NT | FALSE | | | 24.361 | 23.507 | 0.000 | | 21.259 | 24.361 |
| Bonners Ferry, City of | 107 | 2003 | 3 | NT | FALSE | | | 8.527 | 8.527 | 0.000 | | 6.783 | 8.527 |
| Bonners Ferry, City of | 107 | 2003 | 4 | NT | FALSE | | | 7.391 | 5.985 | 0.000 | | 5.567 | 7.391 |
| Bonners Ferry, City of | 107 | 2003 | 5 | NT | FALSE | | | 7.159 | 3.219 | 0.000 | | 2.746 | 7.159 |
| Bonners Ferry, City of | 107 | 2003 | 6 | NT | FALSE | | | 7.581 | 3.361 | 0.000 | | 2.228 | 7.581 |
| Bonners Ferry, City of | 107 | 2003 | 7 | NT | FALSE | | | 7.240 | 3.234 | 0.000 | | 2.693 | 7.240 |
| Bonners Ferry, City of | 107 | 2003 | 8 | NT | FALSE | | | 8.556 | 7.944 | 0.000 | | 6.340 | 8.556 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 7 | NT | FALSE | | | 130.376 | 102.997 | 0.000 | 63.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 8 | NT | FALSE | | | 133.185 | 104.284 | 0.000 | 66.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 9 | NT | FALSE | | | 120.051 | 80.914 | 0.000 | 54.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 10 | NT | FALSE | | | 113.244 | 96.031 | 0.000 | 49.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 11 | NT | FALSE | | | 130.701 | 114.886 | 0.000 | 69.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2000 | 12 | NT | FALSE | | | 173.272 | 169.980 | 0.000 | 86.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 1 | NT | FALSE | | | 199.280 | 189.515 | 0.000 | 86.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 2 | NT | FALSE | | | 150.972 | 147.047 | 0.000 | 85.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 3 | NT | FALSE | | | 154.990 | 154.990 | 0.000 | 70.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 4 | NT | FALSE | | | 128.434 | 119.958 | 0.000 | 71.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 5 | NT | FALSE | | | 115.935 | 94.487 | 0.000 | 48.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 6 | NT | FALSE | | | 120.944 | 113.083 | 0.000 | 53.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 7 | NT | FALSE | | | 138.488 | 109.405 | 0.000 | 63.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 8 | NT | FALSE | | | 140.292 | 109.848 | 0.000 | 66.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 9 | NT | FALSE | | | 120.076 | 80.931 | 0.000 | 54.000 | 0.000 | 0.000 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 10 | NT | FALSE | | | 113.872 | 96.563 | 0.000 | 49.000 | 55.011 | 96.563 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 11 | NT | FALSE | | | 131.559 | 115.641 | 0.000 | 69.000 | 54.990 | 115.641 |
| Central Montana Electric Pwr Coop | 313 | 2001 | 12 | NT | FALSE | | | 174.419 | 171.105 | 0.000 | 86.000 | 86.739 | 171.105 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 1 | NT | FALSE | | | 199.420 | 189.649 | 0.000 | 86.000 | 107.863 | 189.649 |

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Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Central Montana Electric Pwr Coop | 313 | 2002 | 2 | NT | FALSE | | | 151.461 | 147.523 | 0.000 | 85.000 | 64.733 | 147.523 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 3 | NT | FALSE | | | 155.487 | 155.487 | 0.000 | 70.000 | 85.487 | 155.487 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 4 | NT | FALSE | | | 129.157 | 120.633 | 0.000 | 71.000 | 54.319 | 120.633 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 5 | NT | FALSE | | | 116.915 | 95.285 | 0.000 | 48.000 | 56.165 | 95.285 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 6 | NT | FALSE | | | 121.929 | 114.003 | 0.000 | 53.000 | 64.448 | 114.003 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 7 | NT | FALSE | | | 139.749 | 110.402 | 0.000 | 63.000 | 60.065 | 110.402 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 8 | NT | FALSE | | | 140.389 | 109.924 | 0.000 | 66.000 | 58.246 | 109.924 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 9 | NT | FALSE | | | 120.102 | 80.949 | 0.000 | 54.000 | 44.553 | 80.949 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 10 | NT | FALSE | | | 114.503 | 97.098 | 0.000 | 49.000 | 55.546 | 97.098 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 11 | NT | FALSE | | | 132.424 | 116.401 | 0.000 | 69.000 | 55.750 | 116.401 |
| Central Montana Electric Pwr Coop | 313 | 2002 | 12 | NT | FALSE | | | 175.574 | 172.238 | 0.000 | 86.000 | 87.872 | 172.238 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 1 | NT | FALSE | | | 199.561 | 189.782 | 0.000 | 86.000 | 107.996 | 189.782 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 2 | NT | FALSE | | | 151.951 | 148.000 | 0.000 | 85.000 | 65.210 | 148.000 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 3 | NT | FALSE | | | 155.986 | 155.986 | 0.000 | 70.000 | 85.986 | 155.986 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 4 | NT | FALSE | | | 129.885 | 121.312 | 0.000 | 71.000 | 54.998 | 121.312 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 5 | NT | FALSE | | | 117.903 | 96.091 | 0.000 | 48.000 | 56.971 | 96.091 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 6 | NT | FALSE | | | 122.921 | 114.931 | 0.000 | 53.000 | 65.376 | 114.931 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 7 | NT | FALSE | | | 141.021 | 111.407 | 0.000 | 63.000 | 61.070 | 111.407 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 8 | NT | FALSE | | | 140.486 | 110.001 | 0.000 | 66.000 | 58.323 | 110.001 |
| Central Montana Electric Pwr Coop | 313 | 2003 | 9 | NT | FALSE | | | 120.127 | 80.966 | 0.000 | 54.000 | 44.570 | 80.966 |
| Clark County PUD | 216 | 1998 | 10 | NT | TRUE | 434.152 | 645.944 | 597.685 | 477.704 | 150.000 | 155.880 | 418.518 | 569.388 |
| Clark County PUD | 216 | 1998 | 11 | NT | TRUE | 377.626 | 639.417 | 679.343 | 651.334 | 150.000 | 245.959 | 360.091 | 622.592 |
| Clark County PUD | 216 | 1998 | 12 | NT | TRUE | 728.888 | 1010.681 | 926.576 | 694.218 | 150.000 | 81.769 | 714.703 | 891.267 |
| Clark County PUD | 216 | 1999 | 1 | NT | TRUE | 435.387 | 785.178 | 784.081 | 688.894 | 150.000 | 191.858 | 417.449 | 776.400 |
| Clark County PUD | 216 | 1999 | 2 | NT | TRUE | 412.658 | 774.451 | 800.005 | 793.559 | 150.000 | 249.554 | 396.851 | 750.042 |
| Clark County PUD | 216 | 1999 | 3 | NT | TRUE | 414.673 | 726.468 | 890.604 | 591.626 | 150.000 | 172.579 | 414.673 | 726.468 |
| Clark County PUD | 216 | 1999 | 4 | NT | TRUE | 428.342 | 719.310 | 760.026 | 375.128 | 150.000 | 67.909 | 428.342 | 719.310 |
| Clark County PUD | 216 | 1999 | 5 | NT | TRUE | 312.266 | 625.852 | 740.206 | 543.674 | 150.000 | 198.911 | 312.266 | 625.852 |
| Clark County PUD | 216 | 1999 | 6 | NT | TRUE | 106.370 | 448.955 | 538.830 | 294.630 | 150.000 | 162.837 | 106.370 | 448.955 |
| Clark County PUD | 216 | 1999 | 7 | NT | TRUE | 164.473 | 498.675 | 443.224 | 130.704 | 150.000 | 21.014 | 164.473 | 498.675 |
| Clark County PUD | 216 | 1999 | 8 | NT | TRUE | 290.494 | 502.080 | 460.600 | 290.152 | 150.000 | 99.036 | 290.494 | 502.080 |
| Clark County PUD | 216 | 1999 | 9 | NT | TRUE | 297.495 | 531.080 | 535.500 | 357.850 | 150.000 | 124.385 | 297.495 | 531.080 |
| Clark County PUD | 216 | 1999 | 10 | NT | TRUE | 285.607 | 532.191 | 639.000 | 669.129 | 150.000 | 308.469 | 301.241 | 608.747 |
| Clark County PUD | 216 | 1999 | 11 | NT | TRUE | 351.023 | 647.609 | 725.000 | 729.891 | 150.000 | 281.141 | 368.558 | 664.434 |
| Clark County PUD | 216 | 1999 | 12 | NT | TRUE | 384.495 | 701.080 | 853.000 | 868.440 | 150.000 | 323.680 | 398.680 | 820.494 |
| Clark County PUD | 216 | 2000 | 1 | NT | TRUE | 434.219 | 819.033 | 836.000 | 752.647 | 150.000 | 206.807 | 452.157 | 827.811 |
| Clark County PUD | 216 | 2000 | 2 | NT | TRUE | 279.354 | 675.939 | 747.000 | 788.181 | 150.000 | 296.121 | 295.161 | 700.348 |
| Clark County PUD | 216 | 2000 | 3 | NT | FALSE | | | 844.950 | 557.842 | 150.000 | 172.579 | 373.037 | 689.228 |
| Clark County PUD | 216 | 2000 | 4 | NT | FALSE | | | 738.100 | 359.341 | 150.000 | 67.909 | 408.787 | 698.558 |
| Clark County PUD | 216 | 2000 | 5 | NT | FALSE | | | 653.170 | 474.915 | 150.000 | 198.911 | 246.975 | 552.262 |
| Clark County PUD | 216 | 2000 | 6 | NT | FALSE | | | 547.800 | 300.819 | 150.000 | 162.837 | 112.199 | 456.430 |
| Clark County PUD | 216 | 2000 | 7 | NT | FALSE | | | 450.300 | 135.727 | 150.000 | 21.014 | 169.314 | 506.636 |
| Clark County PUD | 216 | 2000 | 8 | NT | FALSE | | | 453.461 | 284.012 | 150.000 | 99.036 | 284.490 | 494.298 |
| Clark County PUD | 216 | 2000 | 9 | NT | FALSE | | | 518.295 | 343.570 | 150.000 | 124.385 | 283.969 | 514.017 |
| Clark County PUD | 216 | 2000 | 10 | NT | FALSE | | | 649.012 | 602.246 | 150.000 | 232.175 | 389.602 | 618.285 |
| Clark County PUD | 216 | 2000 | 11 | NT | FALSE | | | 735.040 | 721.837 | 150.000 | 263.550 | 396.596 | 673.636 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Clark County PUD | 216 | 2000 | 12 | NT | FALSE | | | 863.793 | 757.414 | 150.000 | 202.724 | 532.281 | 830.877 |
| Clark County PUD | 216 | 2001 | 1 | NT | FALSE | | | 846.789 | 755.314 | 150.000 | 199.332 | 470.219 | 838.494 |
| Clark County PUD | 216 | 2001 | 2 | NT | FALSE | | | 843.897 | 859.857 | 150.000 | 272.838 | 417.218 | 791.193 |
| Clark County PUD | 216 | 2001 | 3 | NT | FALSE | | | 797.735 | 522.902 | 150.000 | 172.579 | 329.977 | 650.715 |
| Clark County PUD | 216 | 2001 | 4 | NT | FALSE | | | 681.262 | 318.418 | 150.000 | 67.909 | 358.097 | 644.766 |
| Clark County PUD | 216 | 2001 | 5 | NT | FALSE | | | 611.998 | 442.390 | 150.000 | 198.911 | 216.089 | 517.451 |
| Clark County PUD | 216 | 2001 | 6 | NT | FALSE | | | 506.291 | 272.178 | 150.000 | 162.837 | 85.227 | 421.844 |
| Clark County PUD | 216 | 2001 | 7 | NT | FALSE | | | 481.567 | 157.927 | 150.000 | 21.014 | 190.707 | 541.814 |
| Clark County PUD | 216 | 2001 | 8 | NT | FALSE | | | 484.768 | 310.936 | 0.000 | 99.036 | 310.817 | 528.424 |
| Clark County PUD | 216 | 2001 | 9 | NT | FALSE | | | 526.726 | 350.567 | 0.000 | 124.385 | 296.280 | 522.378 |
| Clark County PUD | 216 | 2001 | 10 | NT | FALSE | | | 659.181 | 611.805 | 0.000 | 232.175 | 387.456 | 619.630 |
| Clark County PUD | 216 | 2001 | 11 | NT | FALSE | | | 745.218 | 731.507 | 0.000 | 263.550 | 444.407 | 707.957 |
| Clark County PUD | 216 | 2001 | 12 | NT | FALSE | | | 874.723 | 767.470 | 0.000 | 202.724 | 602.021 | 804.746 |
| Clark County PUD | 216 | 2002 | 1 | NT | FALSE | | | 857.718 | 765.587 | 0.000 | 199.332 | 606.922 | 806.255 |
| Clark County PUD | 216 | 2002 | 2 | NT | FALSE | | | 858.027 | 873.704 | 0.000 | 272.838 | 568.029 | 840.866 |
| Clark County PUD | 216 | 2002 | 3 | NT | FALSE | | | 809.644 | 531.716 | 0.000 | 172.579 | 426.558 | 599.137 |
| Clark County PUD | 216 | 2002 | 4 | NT | FALSE | | | 691.681 | 325.919 | 0.000 | 67.909 | 430.102 | 498.011 |
| Clark County PUD | 216 | 2002 | 5 | NT | FALSE | | | 622.162 | 450.419 | 0.000 | 198.911 | 292.597 | 491.508 |
| Clark County PUD | 216 | 2002 | 6 | NT | FALSE | | | 514.719 | 277.994 | 0.000 | 162.837 | 192.319 | 355.156 |
| Clark County PUD | 216 | 2002 | 7 | NT | FALSE | | | 489.255 | 163.385 | 0.000 | 21.014 | 326.356 | 347.371 |
| Clark County PUD | 216 | 2002 | 8 | NT | FALSE | | | 492.325 | 317.436 | 0.000 | 99.036 | 324.364 | 423.400 |
| Clark County PUD | 216 | 2002 | 9 | NT | FALSE | | | 535.293 | 357.678 | 0.000 | 124.385 | 319.908 | 444.293 |
| Clark County PUD | 216 | 2002 | 10 | NT | FALSE | | | 669.510 | 621.514 | 0.000 | 232.175 | 397.165 | 629.339 |
| Clark County PUD | 216 | 2002 | 11 | NT | FALSE | | | 755.538 | 741.311 | 0.000 | 263.550 | 454.211 | 717.761 |
| Clark County PUD | 216 | 2002 | 12 | NT | FALSE | | | 885.792 | 777.653 | 0.000 | 202.724 | 612.204 | 814.928 |
| Clark County PUD | 216 | 2003 | 1 | NT | FALSE | | | 868.788 | 775.993 | 0.000 | 199.332 | 617.328 | 816.660 |
| Clark County PUD | 216 | 2003 | 2 | NT | FALSE | | | 872.393 | 887.783 | 0.000 | 272.838 | 582.108 | 854.945 |
| Clark County PUD | 216 | 2003 | 3 | NT | FALSE | | | 821.732 | 540.660 | 0.000 | 172.579 | 435.503 | 608.082 |
| Clark County PUD | 216 | 2003 | 4 | NT | FALSE | | | 702.260 | 333.536 | 0.000 | 67.909 | 437.718 | 505.627 |
| Clark County PUD | 216 | 2003 | 5 | NT | FALSE | | | 632.495 | 458.582 | 0.000 | 198.911 | 300.760 | 499.671 |
| Clark County PUD | 216 | 2003 | 6 | NT | FALSE | | | 523.288 | 283.906 | 0.000 | 162.837 | 198.232 | 361.069 |
| Clark County PUD | 216 | 2003 | 7 | NT | FALSE | | | 497.065 | 168.930 | 0.000 | 21.014 | 331.902 | 352.916 |
| Clark County PUD | 216 | 2003 | 8 | NT | FALSE | | | 500.000 | 324.036 | 0.000 | 99.036 | 330.964 | 430.000 |
| Clark County PUD | 216 | 2003 | 9 | NT | FALSE | | | 544.000 | 364.905 | 0.000 | 124.385 | 327.135 | 451.520 |
| Consolidated Irrigation District #19 | 107 | 2003 | 9 | NT | FALSE | | | 10.600 | 7.341 | 0.000 | | 5.435 | 10.600 |
| Consolidated Irrigation District #19 | 192 | 1998 | 10 | NTP | TRUE | 0.261 | 0.353 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1998 | 11 | NTP | TRUE | 0.437 | 0.591 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1998 | 12 | NTP | TRUE | 0.430 | 0.581 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 1 | NTP | TRUE | 0.533 | 0.720 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 2 | NTP | TRUE | 0.505 | 0.683 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 3 | NTP | TRUE | 0.400 | 0.540 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 4 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 5 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 6 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 7 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 8 | NTP | TRUE | 0.461 | 0.623 | | | | | | |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Consolidated Irrigation District #19 | 192 | 1999 | 9 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 10 | NTP | TRUE | 0.461 | 0.623 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 11 | NTP | TRUE | 0.574 | 0.775 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 1999 | 12 | NTP | TRUE | 0.307 | 0.415 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 2000 | 1 | NTP | TRUE | 0.401 | 0.542 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 2000 | 2 | NTP | TRUE | 0.301 | 0.407 | | | | | | |
| Consolidated Irrigation District #19 | 192 | 2000 | 3 | NTP | FALSE | | | 0.471 | 0.392 | 0.000 | | 0.290 | 0.471 |
| Consolidated Irrigation District #19 | 192 | 2000 | 4 | NTP | FALSE | | | 0.545 | 0.501 | 0.000 | | 0.371 | 0.545 |
| Consolidated Irrigation District #19 | 192 | 2000 | 5 | NTP | FALSE | | | 0.503 | 0.409 | 0.000 | | 0.303 | 0.503 |
| Consolidated Irrigation District #19 | 192 | 2000 | 6 | NTP | FALSE | | | 0.571 | 0.555 | 0.000 | | 0.411 | 0.571 |
| Consolidated Irrigation District #19 | 192 | 2000 | 7 | NTP | FALSE | | | 0.662 | 0.549 | 0.000 | | 0.406 | 0.662 |
| Consolidated Irrigation District #19 | 192 | 2000 | 8 | NTP | FALSE | | | 0.636 | 0.529 | 0.000 | | 0.391 | 0.636 |
| Consolidated Irrigation District #19 | 192 | 2000 | 9 | NTP | FALSE | | | 0.593 | 0.476 | 0.000 | | 0.352 | 0.593 |
| Consolidated Irrigation District #19 | 192 | 2000 | 10 | NTP | FALSE | | | 1.003 | 0.721 | 0.000 | | 0.533 | 1.003 |
| Consolidated Irrigation District #19 | 192 | 2000 | 11 | NTP | FALSE | | | 1.411 | 1.192 | 0.000 | | 0.882 | 1.411 |
| Consolidated Irrigation District #19 | 192 | 2000 | 12 | NTP | FALSE | | | 0.953 | 1.178 | 0.000 | | 0.871 | 0.953 |
| Consolidated Irrigation District #19 | 192 | 2001 | 1 | NTP | FALSE | | | 1.301 | 0.992 | 0.000 | | 0.735 | 1.301 |
| Consolidated Irrigation District #19 | 192 | 2001 | 2 | NTP | FALSE | | | 1.155 | 1.061 | 0.000 | | 0.784 | 1.155 |
| Consolidated Irrigation District #19 | 192 | 2001 | 3 | NTP | FALSE | | | 0.473 | 0.393 | 0.000 | | 0.291 | 0.473 |
| Consolidated Irrigation District #19 | 192 | 2001 | 4 | NTP | FALSE | | | 0.548 | 0.504 | 0.000 | | 0.373 | 0.548 |
| Consolidated Irrigation District #19 | 192 | 2001 | 5 | NTP | FALSE | | | 0.507 | 0.413 | 0.000 | | 0.305 | 0.507 |
| Consolidated Irrigation District #19 | 192 | 2001 | 6 | NTP | FALSE | | | 0.576 | 0.560 | 0.000 | | 0.414 | 0.576 |
| Consolidated Irrigation District #19 | 192 | 2001 | 7 | NTP | FALSE | | | 0.668 | 0.554 | 0.000 | | 0.410 | 0.668 |
| Consolidated Irrigation District #19 | 192 | 2001 | 8 | NTP | FALSE | | | 0.637 | 0.529 | 0.000 | | 0.391 | 0.637 |
| Consolidated Irrigation District #19 | 192 | 2001 | 9 | NTP | FALSE | | | 0.594 | 0.476 | 0.000 | | 0.352 | 0.594 |
| Consolidated Irrigation District #19 | 192 | 2001 | 10 | NT | FALSE | | | 1.008 | 0.725 | 0.000 | | 0.536 | 1.008 |
| Consolidated Irrigation District #19 | 192 | 2001 | 11 | NT | FALSE | | | 1.420 | 1.200 | 0.000 | | 0.888 | 1.420 |
| Consolidated Irrigation District #19 | 192 | 2001 | 12 | NT | FALSE | | | 0.959 | 1.186 | 0.000 | | 0.877 | 0.959 |
| Consolidated Irrigation District #19 | 192 | 2002 | 1 | NT | FALSE | | | 1.302 | 0.993 | 0.000 | | 0.735 | 1.302 |
| Consolidated Irrigation District #19 | 192 | 2002 | 2 | NT | FALSE | | | 1.158 | 1.064 | 0.000 | | 0.787 | 1.158 |
| Consolidated Irrigation District #19 | 192 | 2002 | 3 | NT | FALSE | | | 0.474 | 0.394 | 0.000 | | 0.292 | 0.474 |
| Consolidated Irrigation District #19 | 192 | 2002 | 4 | NT | FALSE | | | 0.551 | 0.507 | 0.000 | | 0.375 | 0.551 |
| Consolidated Irrigation District #19 | 192 | 2002 | 5 | NT | FALSE | | | 0.511 | 0.416 | 0.000 | | 0.308 | 0.511 |
| Consolidated Irrigation District #19 | 192 | 2002 | 6 | NT | FALSE | | | 0.580 | 0.564 | 0.000 | | 0.418 | 0.580 |
| Consolidated Irrigation District #19 | 192 | 2002 | 7 | NT | FALSE | | | 0.674 | 0.559 | 0.000 | | 0.414 | 0.674 |
| Consolidated Irrigation District #19 | 192 | 2002 | 8 | NT | FALSE | | | 0.637 | 0.529 | 0.000 | | 0.392 | 0.637 |
| Consolidated Irrigation District #19 | 192 | 2002 | 9 | NT | FALSE | | | 0.594 | 0.476 | 0.000 | | 0.352 | 0.594 |
| Consolidated Irrigation District #19 | 192 | 2002 | 10 | NT | FALSE | | | 1.014 | 0.729 | 0.000 | | 0.539 | 1.014 |
| Consolidated Irrigation District #19 | 192 | 2002 | 11 | NT | FALSE | | | 1.429 | 1.208 | 0.000 | | 0.894 | 1.429 |
| Consolidated Irrigation District #19 | 192 | 2002 | 12 | NT | FALSE | | | 0.965 | 1.193 | 0.000 | | 0.883 | 0.965 |
| Consolidated Irrigation District #19 | 192 | 2003 | 1 | NT | FALSE | | | 1.303 | 0.994 | 0.000 | | 0.736 | 1.303 |
| Consolidated Irrigation District #19 | 192 | 2003 | 2 | NT | FALSE | | | 1.162 | 1.067 | 0.000 | | 0.789 | 1.162 |
| Consolidated Irrigation District #19 | 192 | 2003 | 3 | NT | FALSE | | | 0.476 | 0.395 | 0.000 | | 0.293 | 0.476 |
| Consolidated Irrigation District #19 | 192 | 2003 | 4 | NT | FALSE | | | 0.554 | 0.509 | 0.000 | | 0.377 | 0.554 |
| Consolidated Irrigation District #19 | 192 | 2003 | 5 | NT | FALSE | | | 0.515 | 0.420 | 0.000 | | 0.311 | 0.515 |
| Consolidated Irrigation District #19 | 192 | 2003 | 6 | NT | FALSE | | | 0.585 | 0.569 | 0.000 | | 0.421 | 0.585 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Consolidated Irrigation District #19 | 192 | 2003 | 7 | NT | FALSE | | | 0.680 | 0.564 | 0.000 | | 0.417 | 0.680 |
| Consolidated Irrigation District #19 | 192 | 2003 | 8 | NT | FALSE | | | 0.637 | 0.530 | 0.000 | | 0.392 | 0.637 |
| Consolidated Irrigation District #19 | 192 | 2003 | 9 | NT | FALSE | | | 0.594 | 0.476 | 0.000 | | 0.352 | 0.594 |
| Cowlitz County PUD | 222 | 1998 | 10 | NTP | TRUE | 220.422 | 223.663 | 577.600 | 466.701 | 318.000 | 0.000 | 200.629 | 202.073 |
| Cowlitz County PUD | 222 | 1998 | 11 | NTP | TRUE | 6.236 | 6.236 | 608.950 | 498.121 | 318.000 | 0.000 | 101.351 | 101.351 |
| Cowlitz County PUD | 222 | 1998 | 12 | NTP | TRUE | 314.353 | 338.353 | 740.300 | 590.019 | 318.000 | 0.000 | 296.833 | 309.319 |
| Cowlitz County PUD | 222 | 1999 | 1 | NTP | TRUE | 225.431 | 242.531 | 643.150 | 526.740 | 318.000 | 0.000 | 221.314 | 229.094 |
| Cowlitz County PUD | 222 | 1999 | 2 | NTP | TRUE | 238.836 | 251.836 | 647.780 | 524.702 | 318.000 | 0.000 | 260.764 | 268.177 |
| Cowlitz County PUD | 222 | 1999 | 3 | NTP | TRUE | 187.344 | 229.344 | 718.750 | 606.625 | 318.000 | 0.000 | 187.344 | 229.344 |
| Cowlitz County PUD | 222 | 1999 | 4 | NTP | TRUE | 249.052 | 249.052 | 671.600 | 554.742 | 318.000 | 0.000 | 249.052 | 249.052 |
| Cowlitz County PUD | 222 | 1999 | 5 | NTP | TRUE | 201.947 | 214.473 | 691.250 | 534.336 | 318.000 | 0.000 | 201.947 | 214.473 |
| Cowlitz County PUD | 222 | 1999 | 6 | NTP | TRUE | 218.894 | 218.894 | 677.600 | 539.370 | 318.000 | 0.000 | 218.894 | 218.894 |
| Cowlitz County PUD | 222 | 1999 | 7 | NTP | TRUE | 191.056 | 191.056 | 476.900 | 394.873 | 318.000 | 0.000 | 191.056 | 191.056 |
| Cowlitz County PUD | 222 | 1999 | 8 | NTP | TRUE | 203.053 | 203.053 | 496.224 | 429.234 | 318.000 | 0.000 | 203.053 | 203.053 |
| Cowlitz County PUD | 222 | 1999 | 9 | NTP | TRUE | 213.038 | 213.338 | 545.066 | 515.632 | 318.000 | 0.000 | 213.038 | 213.338 |
| Cowlitz County PUD | 222 | 1999 | 10 | NTP | TRUE | 230.119 | 230.119 | 611.368 | 493.986 | 288.000 | 0.000 | 249.912 | 251.709 |
| Cowlitz County PUD | 222 | 1999 | 11 | NTP | TRUE | 219.547 | 219.547 | 645.212 | 527.783 | 288.000 | 0.000 | 124.432 | 124.432 |
| Cowlitz County PUD | 222 | 1999 | 12 | NTP | TRUE | 256.228 | 256.228 | 677.456 | 539.932 | 288.000 | 0.000 | 273.748 | 285.262 |
| Cowlitz County PUD | 222 | 2000 | 1 | NTP | TRUE | 260.980 | 260.980 | 677.476 | 554.853 | 288.000 | 0.000 | 265.097 | 274.417 |
| Cowlitz County PUD | 222 | 2000 | 2 | NTP | TRUE | 266.122 | 267.478 | 596.825 | 483.428 | 288.000 | 0.000 | 244.194 | 251.137 |
| Cowlitz County PUD | 222 | 2000 | 3 | NTP | FALSE | | | 674.031 | 568.882 | 288.000 | 0.000 | 180.463 | 220.921 |
| Cowlitz County PUD | 222 | 2000 | 4 | NTP | FALSE | | | 646.017 | 533.610 | 288.000 | 0.000 | 252.163 | 252.163 |
| Cowlitz County PUD | 222 | 2000 | 5 | NTP | FALSE | | | 605.076 | 467.723 | 288.000 | 0.000 | 171.554 | 182.195 |
| Cowlitz County PUD | 222 | 2000 | 6 | NTP | FALSE | | | 683.113 | 543.758 | 288.000 | 0.000 | 240.511 | 240.511 |
| Cowlitz County PUD | 222 | 2000 | 7 | NTP | FALSE | | | 481.242 | 398.469 | 288.000 | 0.000 | 232.348 | 232.348 |
| Cowlitz County PUD | 222 | 2000 | 8 | NTP | FALSE | | | 481.367 | 416.383 | 288.000 | 0.000 | 220.306 | 220.306 |
| Cowlitz County PUD | 222 | 2000 | 9 | NTP | FALSE | | | 519.220 | 491.182 | 288.000 | 0.000 | 216.935 | 217.241 |
| Cowlitz County PUD | 222 | 2000 | 10 | NTP | FALSE | | | 614.755 | 496.722 | 285.000 | 0.000 | 254.848 | 256.681 |
| Cowlitz County PUD | 222 | 2000 | 11 | NTP | FALSE | | | 649.451 | 531.251 | 285.000 | 0.000 | 126.954 | 126.954 |
| Cowlitz County PUD | 222 | 2000 | 12 | NTP | FALSE | | | 681.941 | 543.507 | 285.000 | 0.000 | 279.009 | 290.744 |
| Cowlitz County PUD | 222 | 2001 | 1 | NTP | FALSE | | | 677.953 | 555.243 | 285.000 | 0.000 | 267.464 | 276.867 |
| Cowlitz County PUD | 222 | 2001 | 2 | NTP | FALSE | | | 665.284 | 538.880 | 285.000 | 0.000 | 300.698 | 309.247 |
| Cowlitz County PUD | 222 | 2001 | 3 | NTP | FALSE | | | 629.018 | 530.891 | 285.000 | 0.000 | 160.823 | 196.877 |
| Cowlitz County PUD | 222 | 2001 | 4 | NTP | FALSE | | | 590.595 | 487.831 | 285.000 | 0.000 | 215.241 | 215.241 |
| Cowlitz County PUD | 222 | 2001 | 5 | NTP | FALSE | | | 562.386 | 434.724 | 285.000 | 0.000 | 150.080 | 159.389 |
| Cowlitz County PUD | 222 | 2001 | 6 | NTP | FALSE | | | 626.065 | 498.348 | 285.000 | 0.000 | 207.611 | 207.611 |
| Cowlitz County PUD | 222 | 2001 | 7 | NTP | FALSE | | | 511.183 | 423.260 | 285.000 | 0.000 | 271.955 | 271.955 |
| Cowlitz County PUD | 222 | 2001 | 8 | NTP | FALSE | | | 507.054 | 438.601 | 285.000 | 0.000 | 252.989 | 252.989 |
| Cowlitz County PUD | 222 | 2001 | 9 | NTP | FALSE | | | 519.330 | 491.286 | 285.000 | 0.000 | 219.853 | 220.163 |
| Cowlitz County PUD | 222 | 2001 | 10 | NT | FALSE | | | 618.161 | 499.474 | 135.000 | 0.000 | 425.474 | 499.474 |
| Cowlitz County PUD | 222 | 2001 | 11 | NT | FALSE | | | 653.718 | 534.741 | 135.000 | 0.000 | 460.741 | 534.741 |
| Cowlitz County PUD | 222 | 2001 | 12 | NT | FALSE | | | 686.456 | 547.106 | 135.000 | 0.000 | 473.106 | 547.106 |
| Cowlitz County PUD | 222 | 2002 | 1 | NT | FALSE | | | 678.430 | 555.634 | 135.000 | 0.000 | 481.634 | 555.634 |
| Cowlitz County PUD | 222 | 2002 | 2 | NT | FALSE | | | 667.437 | 540.624 | 135.000 | 0.000 | 466.624 | 540.624 |
| Cowlitz County PUD | 222 | 2002 | 3 | NT | FALSE | | | 631.037 | 532.595 | 135.000 | 0.000 | 458.595 | 532.595 |
| Cowlitz County PUD | 222 | 2002 | 4 | NT | FALSE | | | 593.920 | 490.578 | 135.000 | 0.000 | 416.578 | 490.578 |

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Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Cowlitz County PUD | 222 | 2002 | 5 | NT | FALSE | | | 567.139 | 438.398 | 135.000 | 0.000 | 364.398 | 438.398 |
| Cowlitz County PUD | 222 | 2002 | 6 | NT | FALSE | | | 631.159 | 502.403 | 135.000 | 0.000 | 428.403 | 502.403 |
| Cowlitz County PUD | 222 | 2002 | 7 | NT | FALSE | | | 515.838 | 427.113 | 135.000 | 0.000 | 353.113 | 427.113 |
| Cowlitz County PUD | 222 | 2002 | 8 | NT | FALSE | | | 507.405 | 438.906 | 135.000 | 0.000 | 364.906 | 438.906 |
| Cowlitz County PUD | 222 | 2002 | 9 | NT | FALSE | | | 519.440 | 491.391 | 135.000 | 0.000 | 417.391 | 491.391 |
| Cowlitz County PUD | 222 | 2002 | 10 | NT | FALSE | | | 621.585 | 502.241 | 135.000 | 0.000 | 428.241 | 502.241 |
| Cowlitz County PUD | 222 | 2002 | 11 | NT | FALSE | | | 658.013 | 538.255 | 135.000 | 0.000 | 464.255 | 538.255 |
| Cowlitz County PUD | 222 | 2002 | 12 | NT | FALSE | | | 691.001 | 550.728 | 135.000 | 0.000 | 476.728 | 550.728 |
| Cowlitz County PUD | 222 | 2003 | 1 | NT | FALSE | | | 678.907 | 556.025 | 135.000 | 0.000 | 482.025 | 556.025 |
| Cowlitz County PUD | 222 | 2003 | 2 | NT | FALSE | | | 669.596 | 542.373 | 135.000 | 0.000 | 468.373 | 542.373 |
| Cowlitz County PUD | 222 | 2003 | 3 | NT | FALSE | | | 633.062 | 534.304 | 135.000 | 0.000 | 460.304 | 534.304 |
| Cowlitz County PUD | 222 | 2003 | 4 | NT | FALSE | | | 597.264 | 493.340 | 135.000 | 0.000 | 419.340 | 493.340 |
| Cowlitz County PUD | 222 | 2003 | 5 | NT | FALSE | | | 571.931 | 442.103 | 135.000 | 0.000 | 368.103 | 442.103 |
| Cowlitz County PUD | 222 | 2003 | 6 | NT | FALSE | | | 636.295 | 506.491 | 135.000 | 0.000 | 432.491 | 506.491 |
| Cowlitz County PUD | 222 | 2003 | 7 | NT | FALSE | | | 520.534 | 431.002 | 135.000 | 0.000 | 357.002 | 431.002 |
| Cowlitz County PUD | 222 | 2003 | 8 | NT | FALSE | | | 507.757 | 439.210 | 135.000 | 0.000 | 365.210 | 439.210 |
| Cowlitz County PUD | 222 | 2003 | 9 | NT | FALSE | | | 519.550 | 491.495 | 135.000 | 0.000 | 417.495 | 491.495 |
| Energy Northwest, Inc. | 841 | 1998 | 10 | NT | TRUE | 0.000 | 0.000 | | | | | | |
| Energy Northwest, Inc. | 841 | 1998 | 11 | NT | TRUE | 0.000 | 0.000 | | | | | | |
| Energy Northwest, Inc. | 841 | 1998 | 12 | NT | TRUE | 0.000 | 0.000 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 1 | NT | TRUE | 0.000 | 0.000 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 2 | NT | TRUE | 0.000 | 0.000 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 3 | NT | TRUE | 20.908 | 35.508 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 4 | NT | TRUE | 17.191 | 31.790 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 5 | NT | TRUE | 17.242 | 31.842 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 6 | NT | TRUE | 11.260 | 25.861 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 7 | NT | TRUE | 15.487 | 30.087 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 8 | NT | TRUE | 13.382 | 27.981 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 9 | NT | TRUE | 12.929 | 26.729 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 10 | NT | TRUE | 13.619 | 27.818 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 11 | NT | TRUE | 24.207 | 37.807 | | | | | | |
| Energy Northwest, Inc. | 841 | 1999 | 12 | NT | TRUE | 24.514 | 38.113 | | | | | | |
| Energy Northwest, Inc. | 841 | 2000 | 1 | NT | TRUE | 26.409 | 40.009 | | | | | | |
| Energy Northwest, Inc. | 841 | 2000 | 2 | NT | TRUE | 27.554 | 41.154 | | | | | | |
| Energy Northwest, Inc. | 841 | 2000 | 3 | NT | FALSE | | | 30.976 | 30.976 | 14.000 | | 18.239 | 30.976 |
| Energy Northwest, Inc. | 841 | 2000 | 4 | NT | FALSE | | | 27.799 | 27.799 | 14.000 | | 15.033 | 27.799 |
| Energy Northwest, Inc. | 841 | 2000 | 5 | NT | FALSE | | | 25.689 | 25.689 | 14.000 | | 13.910 | 25.689 |
| Energy Northwest, Inc. | 841 | 2000 | 6 | NT | FALSE | | | 23.701 | 23.701 | 14.000 | | 10.320 | 23.701 |
| Energy Northwest, Inc. | 841 | 2000 | 7 | NT | FALSE | | | 31.959 | 31.959 | 14.000 | | 16.451 | 31.959 |
| Energy Northwest, Inc. | 841 | 2000 | 8 | NT | FALSE | | | 28.572 | 28.572 | 14.000 | | 13.665 | 28.572 |
| Energy Northwest, Inc. | 841 | 2000 | 9 | NT | FALSE | | | 25.462 | 25.462 | 14.000 | | 12.316 | 25.462 |
| Energy Northwest, Inc. | 841 | 2000 | 10 | NT | FALSE | | | 28.049 | 28.049 | 14.000 | | 13.732 | 28.049 |
| Energy Northwest, Inc. | 841 | 2000 | 11 | NT | FALSE | | | 38.180 | 38.180 | 14.000 | | 24.446 | 38.180 |
| Energy Northwest, Inc. | 841 | 2000 | 12 | NT | FALSE | | | 38.492 | 38.492 | 14.000 | | 24.758 | 38.492 |
| Energy Northwest, Inc. | 841 | 2001 | 1 | NT | FALSE | | | 40.051 | 40.051 | 14.000 | | 26.437 | 40.051 |
| Energy Northwest, Inc. | 841 | 2001 | 2 | NT | FALSE | | | 45.949 | 45.949 | 14.000 | | 30.764 | 45.949 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Energy Northwest, Inc. | 841 | 2001 | 3 | NT | FALSE | | | 31.075 | 31.075 | 14.000 | | 18.298 | 31.075 |
| Energy Northwest, Inc. | 841 | 2001 | 4 | NT | FALSE | | | 27.956 | 27.956 | 14.000 | | 15.118 | 27.956 |
| Energy Northwest, Inc. | 841 | 2001 | 5 | NT | FALSE | | | 25.906 | 25.906 | 14.000 | | 14.028 | 25.906 |
| Energy Northwest, Inc. | 841 | 2001 | 6 | NT | FALSE | | | 23.894 | 23.894 | 14.000 | | 10.404 | 23.894 |
| Energy Northwest, Inc. | 841 | 2001 | 7 | NT | FALSE | | | 32.250 | 32.250 | 14.000 | | 16.600 | 32.250 |
| Energy Northwest, Inc. | 841 | 2001 | 8 | NT | FALSE | | | 28.592 | 28.592 | 14.000 | | 13.674 | 28.592 |
| Energy Northwest, Inc. | 841 | 2001 | 9 | NT | FALSE | | | 25.467 | 25.467 | 14.000 | | 12.319 | 25.467 |
| Energy Northwest, Inc. | 841 | 2001 | 10 | NT | FALSE | | | 28.205 | 28.205 | 14.000 | | 13.808 | 28.205 |
| Energy Northwest, Inc. | 841 | 2001 | 11 | NT | FALSE | | | 38.431 | 38.431 | 14.000 | | 24.607 | 38.431 |
| Energy Northwest, Inc. | 841 | 2001 | 12 | NT | FALSE | | | 38.747 | 38.747 | 14.000 | | 24.922 | 38.747 |
| Energy Northwest, Inc. | 841 | 2002 | 1 | NT | FALSE | | | 40.079 | 40.079 | 14.000 | | 26.455 | 40.079 |
| Energy Northwest, Inc. | 841 | 2002 | 2 | NT | FALSE | | | 46.097 | 46.097 | 14.000 | | 30.864 | 46.097 |
| Energy Northwest, Inc. | 841 | 2002 | 3 | NT | FALSE | | | 31.175 | 31.175 | 14.000 | | 18.356 | 31.175 |
| Energy Northwest, Inc. | 841 | 2002 | 4 | NT | FALSE | | | 28.113 | 28.113 | 14.000 | | 15.203 | 28.113 |
| Energy Northwest, Inc. | 841 | 2002 | 5 | NT | FALSE | | | 26.125 | 26.125 | 14.000 | | 14.146 | 26.125 |
| Energy Northwest, Inc. | 841 | 2002 | 6 | NT | FALSE | | | 24.089 | 24.089 | 14.000 | | 10.488 | 24.089 |
| Energy Northwest, Inc. | 841 | 2002 | 7 | NT | FALSE | | | 32.544 | 32.544 | 14.000 | | 16.751 | 32.544 |
| Energy Northwest, Inc. | 841 | 2002 | 8 | NT | FALSE | | | 28.611 | 28.611 | 14.000 | | 13.684 | 28.611 |
| Energy Northwest, Inc. | 841 | 2002 | 9 | NT | FALSE | | | 25.472 | 25.472 | 14.000 | | 12.321 | 25.472 |
| Energy Northwest, Inc. | 841 | 2002 | 10 | NT | FALSE | | | 28.361 | 28.361 | 14.000 | | 13.885 | 28.361 |
| Energy Northwest, Inc. | 841 | 2002 | 11 | NT | FALSE | | | 38.684 | 38.684 | 14.000 | | 24.768 | 38.684 |
| Energy Northwest, Inc. | 841 | 2002 | 12 | NT | FALSE | | | 39.004 | 39.004 | 14.000 | | 25.087 | 39.004 |
| Energy Northwest, Inc. | 841 | 2003 | 1 | NT | FALSE | | | 40.108 | 40.108 | 14.000 | | 26.474 | 40.108 |
| Energy Northwest, Inc. | 841 | 2003 | 2 | NT | FALSE | | | 46.247 | 46.247 | 14.000 | | 30.964 | 46.247 |
| Energy Northwest, Inc. | 841 | 2003 | 3 | NT | FALSE | | | 31.275 | 31.275 | 14.000 | | 18.415 | 31.275 |
| Energy Northwest, Inc. | 841 | 2003 | 4 | NT | FALSE | | | 28.271 | 28.271 | 14.000 | | 15.288 | 28.271 |
| Energy Northwest, Inc. | 841 | 2003 | 5 | NT | FALSE | | | 26.346 | 26.346 | 14.000 | | 14.266 | 26.346 |
| Energy Northwest, Inc. | 841 | 2003 | 6 | NT | FALSE | | | 24.285 | 24.285 | 14.000 | | 10.574 | 24.285 |
| Energy Northwest, Inc. | 841 | 2003 | 7 | NT | FALSE | | | 32.840 | 32.840 | 14.000 | | 16.904 | 32.840 |
| Energy Northwest, Inc. | 841 | 2003 | 8 | NT | FALSE | | | 28.631 | 28.631 | 14.000 | | 13.693 | 28.631 |
| Energy Northwest, Inc. | 841 | 2003 | 9 | NT | FALSE | | | 25.478 | 25.478 | 14.000 | | 12.324 | 25.478 |
| Okanogan County PUD | 266 | 1998 | 10 | NTP | TRUE | 36.000 | 37.149 | 93.351 | 86.701 | 11.000 | 46.351 | 36.000 | 36.910 |
| Okanogan County PUD | 266 | 1998 | 11 | NTP | TRUE | 36.000 | 41.064 | 113.530 | 93.887 | 11.000 | 66.530 | 36.000 | 38.279 |
| Okanogan County PUD | 266 | 1998 | 12 | NTP | TRUE | 69.000 | 76.400 | 150.155 | 146.889 | 11.000 | 70.155 | 69.000 | 74.927 |
| Okanogan County PUD | 266 | 1999 | 1 | NTP | TRUE | 60.000 | 64.400 | 123.979 | 123.959 | 11.000 | 52.979 | 60.000 | 62.203 |
| Okanogan County PUD | 266 | 1999 | 2 | NTP | TRUE | 60.000 | 60.700 | 122.995 | 113.519 | 11.000 | 51.995 | 60.000 | 60.564 |
| Okanogan County PUD | 266 | 1999 | 3 | NTP | TRUE | 41.000 | 45.045 | 121.052 | 137.105 | 11.000 | 69.052 | 41.000 | 45.045 |
| Okanogan County PUD | 266 | 1999 | 4 | NTP | TRUE | 35.000 | 38.416 | 107.254 | 116.509 | 11.000 | 61.254 | 35.000 | 38.416 |
| Okanogan County PUD | 266 | 1999 | 5 | NTP | TRUE | 31.000 | 31.300 | 111.884 | 112.313 | 11.000 | 69.884 | 31.000 | 31.300 |
| Okanogan County PUD | 266 | 1999 | 6 | NTP | TRUE | 16.000 | 16.300 | 95.992 | 96.858 | 11.000 | 68.992 | 16.000 | 16.300 |
| Okanogan County PUD | 266 | 1999 | 7 | NTP | TRUE | 30.000 | 31.763 | 82.182 | 43.586 | 11.000 | 41.182 | 30.000 | 31.763 |
| Okanogan County PUD | 266 | 1999 | 8 | NTP | TRUE | 33.000 | 33.700 | 82.320 | 58.502 | 11.000 | 38.320 | 33.000 | 33.700 |
| Okanogan County PUD | 266 | 1999 | 9 | NTP | TRUE | 37.000 | 42.238 | 98.700 | 79.818 | 11.000 | 50.700 | 37.000 | 42.238 |
| Okanogan County PUD | 266 | 1999 | 10 | NTP | TRUE | 44.000 | 44.874 | 99.000 | 90.000 | 11.000 | 44.000 | 44.000 | 45.113 |
| Okanogan County PUD | 266 | 1999 | 11 | NTP | TRUE | 44.000 | 44.000 | 120.000 | 96.880 | 11.000 | 65.000 | 44.000 | 46.785 |
| Okanogan County PUD | 266 | 1999 | 12 | NTP | TRUE | 44.000 | 46.307 | 137.000 | 147.368 | 11.000 | 82.000 | 44.000 | 47.780 |

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Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Okanogan County PUD | 266 | 2000 | 1 | NTP | TRUE | 68.000 | 68.300 | 131.000 | 130.000 | 11.000 | 52.000 | 68.000 | 70.497 |
| Okanogan County PUD | 266 | 2000 | 2 | NTP | TRUE | 57.000 | 57.400 | 113.400 | 98.068 | 11.000 | 45.400 | 57.000 | 57.536 |
| Okanogan County PUD | 266 | 2000 | 3 | NTP | FALSE | | | 113.950 | 130.002 | 11.000 | 69.052 | 33.898 | 37.242 |
| Okanogan County PUD | 266 | 2000 | 4 | NTP | FALSE | | | 103.400 | 112.654 | 11.000 | 61.254 | 31.146 | 34.186 |
| Okanogan County PUD | 266 | 2000 | 5 | NTP | FALSE | | | 97.650 | 100.300 | 11.000 | 69.884 | 16.766 | 16.928 |
| Okanogan County PUD | 266 | 2000 | 6 | NTP | FALSE | | | 96.800 | 97.530 | 11.000 | 68.992 | 16.808 | 17.123 |
| Okanogan County PUD | 266 | 2000 | 7 | NTP | FALSE | | | 82.650 | 43.896 | 11.000 | 41.182 | 30.468 | 32.259 |
| Okanogan County PUD | 266 | 2000 | 8 | NTP | FALSE | | | 80.271 | 56.681 | 11.000 | 38.320 | 30.951 | 31.608 |
| Okanogan County PUD | 266 | 2000 | 9 | NTP | FALSE | | | 94.741 | 76.525 | 11.000 | 50.700 | 33.041 | 37.719 |
| Okanogan County PUD | 266 | 2000 | 10 | NTP | FALSE | | | 99.742 | 91.917 | 11.000 | 45.175 | 43.566 | 44.668 |
| Okanogan County PUD | 266 | 2000 | 11 | NTP | FALSE | | | 120.497 | 97.992 | 11.000 | 65.765 | 43.732 | 46.500 |
| Okanogan County PUD | 266 | 2000 | 12 | NTP | FALSE | | | 137.497 | 141.875 | 11.000 | 76.077 | 50.420 | 54.751 |
| Okanogan County PUD | 266 | 2001 | 1 | NTP | FALSE | | | 131.497 | 130.987 | 11.000 | 52.490 | 68.007 | 70.504 |
| Okanogan County PUD | 266 | 2001 | 2 | NTP | FALSE | | | 126.497 | 113.454 | 11.000 | 48.697 | 66.800 | 67.428 |
| Okanogan County PUD | 266 | 2001 | 3 | NTP | FALSE | | | 106.742 | 122.795 | 11.000 | 69.052 | 26.690 | 29.323 |
| Okanogan County PUD | 266 | 2001 | 4 | NTP | FALSE | | | 94.741 | 103.995 | 11.000 | 61.254 | 22.487 | 24.682 |
| Okanogan County PUD | 266 | 2001 | 5 | NTP | FALSE | | | 90.496 | 94.262 | 11.000 | 69.884 | 9.612 | 9.705 |
| Okanogan County PUD | 266 | 2001 | 6 | NTP | FALSE | | | 88.741 | 90.824 | 11.000 | 68.992 | 8.748 | 8.912 |
| Okanogan County PUD | 266 | 2001 | 7 | NTP | FALSE | | | 87.496 | 47.104 | 11.000 | 41.182 | 35.314 | 37.389 |
| Okanogan County PUD | 266 | 2001 | 8 | NTP | FALSE | | | 84.994 | 60.880 | 11.000 | 38.320 | 35.674 | 36.431 |
| Okanogan County PUD | 266 | 2001 | 9 | NTP | FALSE | | | 95.488 | 77.146 | 11.000 | 50.700 | 33.788 | 38.571 |
| Okanogan County PUD | 266 | 2001 | 10 | NT | FALSE | | | 100.489 | 92.664 | 0.000 | 56.175 | 44.313 | 100.489 |
| Okanogan County PUD | 266 | 2001 | 11 | NT | FALSE | | | 120.996 | 98.341 | 0.000 | 76.765 | 7.811 | 84.576 |
| Okanogan County PUD | 266 | 2001 | 12 | NT | FALSE | | | 137.996 | 142.306 | 0.000 | 87.077 | 32.151 | 119.229 |
| Okanogan County PUD | 266 | 2002 | 1 | NT | FALSE | | | 131.996 | 131.486 | 0.000 | 63.490 | 68.506 | 131.996 |
| Okanogan County PUD | 266 | 2002 | 2 | NT | FALSE | | | 126.996 | 113.915 | 0.000 | 59.697 | 57.520 | 117.217 |
| Okanogan County PUD | 266 | 2002 | 3 | NT | FALSE | | | 107.490 | 123.542 | 0.000 | 80.052 | 27.437 | 107.490 |
| Okanogan County PUD | 266 | 2002 | 4 | NT | FALSE | | | 95.488 | 104.743 | 0.000 | 72.254 | 23.234 | 95.488 |
| Okanogan County PUD | 266 | 2002 | 5 | NT | FALSE | | | 90.995 | 94.683 | 0.000 | 80.884 | 0.000 | 76.799 |
| Okanogan County PUD | 266 | 2002 | 6 | NT | FALSE | | | 89.487 | 91.446 | 0.000 | 79.992 | 0.000 | 74.454 |
| Okanogan County PUD | 266 | 2002 | 7 | NT | FALSE | | | 87.994 | 47.434 | 0.000 | 52.182 | 6.071 | 58.252 |
| Okanogan County PUD | 266 | 2002 | 8 | NT | FALSE | | | 85.496 | 61.326 | 0.000 | 49.320 | 26.686 | 76.006 |
| Okanogan County PUD | 266 | 2002 | 9 | NT | FALSE | | | 96.241 | 77.773 | 0.000 | 61.700 | 18.373 | 80.073 |
| Okanogan County PUD | 266 | 2002 | 10 | NT | FALSE | | | 101.242 | 93.417 | 0.000 | 56.175 | 45.066 | 101.242 |
| Okanogan County PUD | 266 | 2002 | 11 | NT | FALSE | | | 121.497 | 98.691 | 0.000 | 76.765 | 8.161 | 84.926 |
| Okanogan County PUD | 266 | 2002 | 12 | NT | FALSE | | | 138.497 | 142.739 | 0.000 | 87.077 | 32.584 | 119.662 |
| Okanogan County PUD | 266 | 2003 | 1 | NT | FALSE | | | 132.497 | 131.987 | 0.000 | 63.490 | 69.007 | 132.497 |
| Okanogan County PUD | 266 | 2003 | 2 | NT | FALSE | | | 127.497 | 114.377 | 0.000 | 59.697 | 57.982 | 117.680 |
| Okanogan County PUD | 266 | 2003 | 3 | NT | FALSE | | | 108.242 | 124.295 | 0.000 | 80.052 | 28.190 | 108.242 |
| Okanogan County PUD | 266 | 2003 | 4 | NT | FALSE | | | 96.241 | 105.495 | 0.000 | 72.254 | 23.987 | 96.241 |
| Okanogan County PUD | 266 | 2003 | 5 | NT | FALSE | | | 91.496 | 95.106 | 0.000 | 80.884 | 0.000 | 77.223 |
| Okanogan County PUD | 266 | 2003 | 6 | NT | FALSE | | | 90.241 | 92.072 | 0.000 | 79.992 | 0.000 | 75.080 |
| Okanogan County PUD | 266 | 2003 | 7 | NT | FALSE | | | 88.496 | 47.766 | 0.000 | 52.182 | 6.402 | 58.584 |
| Okanogan County PUD | 266 | 2003 | 8 | NT | FALSE | | | 86.000 | 61.774 | 0.000 | 49.320 | 27.134 | 76.454 |
| Okanogan County PUD | 266 | 2003 | 9 | NT | FALSE | | | 97.000 | 78.404 | 0.000 | 61.700 | 19.004 | 80.704 |
| Pend Oreille County PUD | 273 | 1998 | 10 | NTP | TRUE | 31.014 | 31.508 | 118.465 | 113.963 | 51.000 | 0.000 | 38.054 | 38.289 |

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Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Pend Oreille County PUD | 273 | 1998 | 11 | NTP | TRUE | 44.728 | 44.728 | 123.595 | 96.281 | 51.000 | 0.000 | 41.272 | 46.112 |
| Pend Oreille County PUD | 273 | 1998 | 12 | NTP | TRUE | 63.161 | 64.608 | 153.450 | 112.632 | 51.000 | 0.000 | 58.286 | 59.058 |
| Pend Oreille County PUD | 273 | 1999 | 1 | NTP | TRUE | 56.461 | 57.211 | 134.235 | 104.838 | 51.000 | 0.000 | 51.993 | 57.812 |
| Pend Oreille County PUD | 273 | 1999 | 2 | NTP | TRUE | 56.536 | 56.536 | 149.352 | 77.962 | 51.000 | 0.000 | 58.247 | 59.734 |
| Pend Oreille County PUD | 273 | 1999 | 3 | NTP | TRUE | 47.626 | 53.604 | 158.700 | 70.304 | 51.000 | 0.000 | 47.626 | 53.604 |
| Pend Oreille County PUD | 273 | 1999 | 4 | NTP | TRUE | 50.678 | 50.678 | 154.100 | 95.696 | 51.000 | 0.000 | 50.678 | 50.678 |
| Pend Oreille County PUD | 273 | 1999 | 5 | NTP | TRUE | 31.776 | 31.776 | 163.250 | 118.683 | 51.000 | 0.000 | 31.776 | 31.776 |
| Pend Oreille County PUD | 273 | 1999 | 6 | NTP | TRUE | 20.671 | 20.777 | 132.990 | 129.399 | 51.000 | 0.000 | 20.671 | 20.777 |
| Pend Oreille County PUD | 273 | 1999 | 7 | NTP | TRUE | 27.581 | 27.581 | 106.780 | 100.694 | 51.000 | 0.000 | 27.581 | 27.581 |
| Pend Oreille County PUD | 273 | 1999 | 8 | NTP | TRUE | 24.514 | 24.514 | 107.483 | 104.688 | 51.000 | 0.000 | 24.514 | 24.514 |
| Pend Oreille County PUD | 273 | 1999 | 9 | NTP | TRUE | 48.708 | 48.708 | 118.465 | 91.100 | 51.000 | 0.000 | 48.708 | 48.708 |
| Pend Oreille County PUD | 273 | 1999 | 10 | NTP | TRUE | 49.000 | 49.000 | 125.391 | 120.626 | 51.000 | 0.000 | 41.960 | 42.219 |
| Pend Oreille County PUD | 273 | 1999 | 11 | NTP | TRUE | 42.000 | 52.170 | 130.955 | 102.014 | 51.000 | 0.000 | 45.456 | 50.786 |
| Pend Oreille County PUD | 273 | 1999 | 12 | NTP | TRUE | 46.000 | 46.000 | 140.424 | 103.071 | 51.000 | 0.000 | 50.875 | 51.550 |
| Pend Oreille County PUD | 273 | 2000 | 1 | NTP | TRUE | 52.000 | 63.388 | 141.399 | 110.433 | 51.000 | 0.000 | 56.468 | 62.787 |
| Pend Oreille County PUD | 273 | 2000 | 2 | NTP | TRUE | 53.000 | 55.797 | 137.604 | 71.829 | 51.000 | 0.000 | 51.289 | 52.599 |
| Pend Oreille County PUD | 273 | 2000 | 3 | NTP | FALSE | | | 148.826 | 65.930 | 51.000 | 0.000 | 43.260 | 48.690 |
| Pend Oreille County PUD | 273 | 2000 | 4 | NTP | FALSE | | | 148.230 | 92.051 | 51.000 | 0.000 | 47.793 | 47.793 |
| Pend Oreille County PUD | 273 | 2000 | 5 | NTP | FALSE | | | 142.898 | 103.887 | 51.000 | 0.000 | 26.015 | 26.015 |
| Pend Oreille County PUD | 273 | 2000 | 6 | NTP | FALSE | | | 134.072 | 130.452 | 51.000 | 0.000 | 20.944 | 21.051 |
| Pend Oreille County PUD | 273 | 2000 | 7 | NTP | FALSE | | | 107.752 | 101.610 | 51.000 | 0.000 | 28.062 | 28.062 |
| Pend Oreille County PUD | 273 | 2000 | 8 | NTP | FALSE | | | 104.264 | 101.554 | 51.000 | 0.000 | 23.117 | 23.117 |
| Pend Oreille County PUD | 273 | 2000 | 9 | NTP | FALSE | | | 112.848 | 86.780 | 51.000 | 0.000 | 44.653 | 44.653 |
| Pend Oreille County PUD | 273 | 2000 | 10 | NTP | FALSE | | | 126.085 | 121.294 | 51.000 | 0.000 | 42.352 | 42.613 |
| Pend Oreille County PUD | 273 | 2000 | 11 | NTP | FALSE | | | 131.815 | 102.684 | 51.000 | 0.000 | 45.945 | 51.333 |
| Pend Oreille County PUD | 273 | 2000 | 12 | NTP | FALSE | | | 141.353 | 103.753 | 51.000 | 0.000 | 51.404 | 52.085 |
| Pend Oreille County PUD | 273 | 2001 | 1 | NTP | FALSE | | | 141.499 | 110.511 | 51.000 | 0.000 | 56.530 | 62.857 |
| Pend Oreille County PUD | 273 | 2001 | 2 | NTP | FALSE | | | 153.388 | 80.068 | 51.000 | 0.000 | 60.637 | 62.185 |
| Pend Oreille County PUD | 273 | 2001 | 3 | NTP | FALSE | | | 138.887 | 61.527 | 51.000 | 0.000 | 38.864 | 43.743 |
| Pend Oreille County PUD | 273 | 2001 | 4 | NTP | FALSE | | | 135.513 | 84.154 | 51.000 | 0.000 | 41.542 | 41.542 |
| Pend Oreille County PUD | 273 | 2001 | 5 | NTP | FALSE | | | 132.817 | 96.558 | 51.000 | 0.000 | 23.161 | 23.161 |
| Pend Oreille County PUD | 273 | 2001 | 6 | NTP | FALSE | | | 122.875 | 119.558 | 51.000 | 0.000 | 18.121 | 18.214 |
| Pend Oreille County PUD | 273 | 2001 | 7 | NTP | FALSE | | | 114.456 | 107.932 | 51.000 | 0.000 | 31.376 | 31.376 |
| Pend Oreille County PUD | 273 | 2001 | 8 | NTP | FALSE | | | 109.828 | 106.973 | 51.000 | 0.000 | 25.532 | 25.532 |
| Pend Oreille County PUD | 273 | 2001 | 9 | NTP | FALSE | | | 112.872 | 86.798 | 51.000 | 0.000 | 44.670 | 44.670 |
| Pend Oreille County PUD | 273 | 2001 | 10 | NT | FALSE | | | 126.784 | 121.966 | 51.000 | 0.000 | 121.666 | 121.966 |
| Pend Oreille County PUD | 273 | 2001 | 11 | NT | FALSE | | | 132.681 | 103.359 | 51.000 | 0.000 | 103.059 | 103.359 |
| Pend Oreille County PUD | 273 | 2001 | 12 | NT | FALSE | | | 142.289 | 104.440 | 51.000 | 0.000 | 104.140 | 104.440 |
| Pend Oreille County PUD | 273 | 2002 | 1 | NT | FALSE | | | 141.598 | 110.588 | 51.000 | 0.000 | 110.288 | 110.588 |
| Pend Oreille County PUD | 273 | 2002 | 2 | NT | FALSE | | | 153.884 | 80.328 | 51.000 | 0.000 | 80.028 | 80.328 |
| Pend Oreille County PUD | 273 | 2002 | 3 | NT | FALSE | | | 139.333 | 61.724 | 51.000 | 0.000 | 61.324 | 61.724 |
| Pend Oreille County PUD | 273 | 2002 | 4 | NT | FALSE | | | 136.276 | 84.628 | 51.000 | 0.000 | 84.228 | 84.628 |
| Pend Oreille County PUD | 273 | 2002 | 5 | NT | FALSE | | | 133.939 | 97.374 | 51.000 | 0.000 | 96.974 | 97.374 |
| Pend Oreille County PUD | 273 | 2002 | 6 | NT | FALSE | | | 123.875 | 120.531 | 51.000 | 0.000 | 120.131 | 120.531 |
| Pend Oreille County PUD | 273 | 2002 | 7 | NT | FALSE | | | 115.498 | 108.915 | 51.000 | 0.000 | 108.615 | 108.915 |
| Pend Oreille County PUD | 273 | 2002 | 8 | NT | FALSE | | | 109.904 | 107.047 | 51.000 | 0.000 | 106.747 | 107.047 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Pend Oreille County PUD | 273 | 2002 | 9 | NT | FALSE | | | 112.896 | 86.817 | 51.000 | 0.000 | 86.517 | 86.817 |
| Pend Oreille County PUD | 273 | 2002 | 10 | NT | FALSE | | | 127.486 | 122.642 | 51.000 | 0.000 | 122.342 | 122.642 |
| Pend Oreille County PUD | 273 | 2002 | 11 | NT | FALSE | | | 133.553 | 104.038 | 51.000 | 0.000 | 103.738 | 104.038 |
| Pend Oreille County PUD | 273 | 2002 | 12 | NT | FALSE | | | 143.231 | 105.132 | 51.000 | 0.000 | 104.832 | 105.132 |
| Pend Oreille County PUD | 273 | 2003 | 1 | NT | FALSE | | | 141.698 | 110.666 | 51.000 | 0.000 | 110.366 | 110.666 |
| Pend Oreille County PUD | 273 | 2003 | 2 | NT | FALSE | | | 154.382 | 80.587 | 51.000 | 0.000 | 80.287 | 80.587 |
| Pend Oreille County PUD | 273 | 2003 | 3 | NT | FALSE | | | 139.780 | 61.923 | 51.000 | 0.000 | 61.523 | 61.923 |
| Pend Oreille County PUD | 273 | 2003 | 4 | NT | FALSE | | | 137.044 | 85.104 | 51.000 | 0.000 | 84.704 | 85.104 |
| Pend Oreille County PUD | 273 | 2003 | 5 | NT | FALSE | | | 135.071 | 98.197 | 51.000 | 0.000 | 97.797 | 98.197 |
| Pend Oreille County PUD | 273 | 2003 | 6 | NT | FALSE | | | 124.883 | 121.511 | 51.000 | 0.000 | 121.111 | 121.511 |
| Pend Oreille County PUD | 273 | 2003 | 7 | NT | FALSE | | | 116.550 | 109.907 | 51.000 | 0.000 | 109.607 | 109.907 |
| Pend Oreille County PUD | 273 | 2003 | 8 | NT | FALSE | | | 109.981 | 107.121 | 51.000 | 0.000 | 106.821 | 107.121 |
| Pend Oreille County PUD | 273 | 2003 | 9 | NT | FALSE | | | 112.920 | 86.835 | 51.000 | 0.000 | 86.535 | 86.835 |
| Port Townsend Paper Co. | 716 | 1998 | 10 | NTP | TRUE | 18.400 | 0.000 | 14.820 | 12.849 | 0.000 | 0.000 | 18.363 | 0.000 |
| Port Townsend Paper Co. | 716 | 1998 | 11 | NTP | TRUE | 18.400 | 0.000 | 14.820 | 13.768 | 0.000 | 0.000 | 18.353 | 0.000 |
| Port Townsend Paper Co. | 716 | 1998 | 12 | NTP | TRUE | 18.400 | 0.000 | 17.160 | 15.942 | 0.000 | 0.000 | 19.738 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 1 | NTP | TRUE | 18.400 | 0.000 | 14.830 | 13.688 | 0.000 | 0.000 | 18.408 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 2 | NTP | TRUE | 18.400 | 0.000 | 15.337 | 15.337 | 0.000 | 0.000 | 19.673 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 3 | NTP | TRUE | 18.400 | 0.000 | 17.998 | 16.504 | 0.000 | 0.000 | 18.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 4 | NTP | TRUE | 19.400 | 0.000 | 18.041 | 16.544 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 5 | NTP | TRUE | 19.400 | 0.000 | 19.665 | 3.028 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 6 | NTP | TRUE | 19.400 | 0.000 | 17.300 | 15.137 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 7 | NTP | TRUE | 19.400 | 0.000 | 14.955 | 13.714 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 8 | NTP | TRUE | 19.400 | 0.000 | 15.299 | 12.744 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 9 | NTP | TRUE | 19.400 | 0.000 | 16.383 | 15.024 | 0.000 | 0.000 | 19.400 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 10 | NTP | TRUE | 19.400 | 0.000 | 15.686 | 13.600 | 0.000 | 0.000 | 19.437 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 11 | NTP | TRUE | 19.400 | 0.000 | 15.702 | 14.588 | 0.000 | 0.000 | 19.447 | 0.000 |
| Port Townsend Paper Co. | 716 | 1999 | 12 | NTP | TRUE | 19.400 | 0.000 | 15.703 | 14.588 | 0.000 | 0.000 | 18.062 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 1 | NTP | TRUE | 19.400 | 0.000 | 15.622 | 14.419 | 0.000 | 0.000 | 19.392 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 2 | NTP | TRUE | 19.400 | 0.000 | 14.131 | 14.131 | 0.000 | 0.000 | 18.127 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 3 | NTP | FALSE | | | 16.878 | 15.477 | 0.000 | 0.000 | 17.255 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 4 | NTP | FALSE | | | 17.354 | 15.913 | 0.000 | 0.000 | 18.660 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 5 | NTP | FALSE | | | 17.213 | 2.651 | 0.000 | 0.000 | 16.985 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 6 | NTP | FALSE | | | 17.440 | 15.260 | 0.000 | 0.000 | 19.558 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 7 | NTP | FALSE | | | 15.091 | 13.839 | 0.000 | 0.000 | 19.577 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 8 | NTP | FALSE | | | 14.841 | 12.362 | 0.000 | 0.000 | 18.818 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 9 | NTP | FALSE | | | 15.607 | 14.311 | 0.000 | 0.000 | 18.479 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 10 | NTP | FALSE | | | 15.773 | 13.675 | 0.000 | 0.000 | 19.544 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 11 | NTP | FALSE | | | 15.806 | 14.683 | 0.000 | 0.000 | 19.573 | 0.000 |
| Port Townsend Paper Co. | 716 | 2000 | 12 | NTP | FALSE | | | 15.807 | 14.685 | 0.000 | 0.000 | 18.182 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 1 | NTP | FALSE | | | 15.633 | 14.429 | 0.000 | 0.000 | 19.405 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 2 | NTP | FALSE | | | 15.752 | 15.752 | 0.000 | 0.000 | 20.206 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 3 | NTP | FALSE | | | 15.751 | 14.443 | 0.000 | 0.000 | 16.102 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 4 | NTP | FALSE | | | 15.865 | 14.548 | 0.000 | 0.000 | 17.059 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 5 | NTP | FALSE | | | 15.999 | 2.464 | 0.000 | 0.000 | 15.787 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 6 | NTP | FALSE | | | 15.984 | 13.986 | 0.000 | 0.000 | 17.925 | 0.000 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| Port Townsend Paper Co. | 716 | 2001 | 7 | NTP | FALSE | | | 16.030 | 14.700 | 0.000 | 0.000 | 20.795 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 8 | NTP | FALSE | | | 15.632 | 13.022 | 0.000 | 0.000 | 19.823 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 9 | NTP | FALSE | | | 15.610 | 14.314 | 0.000 | 0.000 | 18.483 | 0.000 |
| Port Townsend Paper Co. | 716 | 2001 | 10 | NT | FALSE | | | 15.861 | 13.751 | 0.000 | 0.000 | 13.751 | 13.751 |
| Port Townsend Paper Co. | 716 | 2001 | 11 | NT | FALSE | | | 15.910 | 14.780 | 0.000 | 0.000 | 14.780 | 14.780 |
| Port Townsend Paper Co. | 716 | 2001 | 12 | NT | FALSE | | | 15.912 | 14.782 | 0.000 | 0.000 | 14.782 | 14.782 |
| Port Townsend Paper Co. | 716 | 2002 | 1 | NT | FALSE | | | 15.644 | 14.439 | 0.000 | 0.000 | 14.439 | 14.439 |
| Port Townsend Paper Co. | 716 | 2002 | 2 | NT | FALSE | | | 15.803 | 15.803 | 0.000 | 0.000 | 15.803 | 15.803 |
| Port Townsend Paper Co. | 716 | 2002 | 3 | NT | FALSE | | | 15.801 | 14.490 | 0.000 | 0.000 | 14.490 | 14.490 |
| Port Townsend Paper Co. | 716 | 2002 | 4 | NT | FALSE | | | 15.954 | 14.630 | 0.000 | 0.000 | 14.630 | 14.630 |
| Port Townsend Paper Co. | 716 | 2002 | 5 | NT | FALSE | | | 16.134 | 2.485 | 0.000 | 0.000 | 2.485 | 2.485 |
| Port Townsend Paper Co. | 716 | 2002 | 6 | NT | FALSE | | | 16.114 | 14.100 | 0.000 | 0.000 | 14.100 | 14.100 |
| Port Townsend Paper Co. | 716 | 2002 | 7 | NT | FALSE | | | 16.176 | 14.833 | 0.000 | 0.000 | 14.833 | 14.833 |
| Port Townsend Paper Co. | 716 | 2002 | 8 | NT | FALSE | | | 15.643 | 13.031 | 0.000 | 0.000 | 13.031 | 13.031 |
| Port Townsend Paper Co. | 716 | 2002 | 9 | NT | FALSE | | | 15.613 | 14.317 | 0.000 | 0.000 | 14.317 | 14.317 |
| Port Townsend Paper Co. | 716 | 2002 | 10 | NT | FALSE | | | 15.949 | 13.827 | 0.000 | 0.000 | 13.827 | 13.827 |
| Port Townsend Paper Co. | 716 | 2002 | 11 | NT | FALSE | | | 16.014 | 14.877 | 0.000 | 0.000 | 14.877 | 14.877 |
| Port Townsend Paper Co. | 716 | 2002 | 12 | NT | FALSE | | | 16.017 | 14.880 | 0.000 | 0.000 | 14.880 | 14.880 |
| Port Townsend Paper Co. | 716 | 2003 | 1 | NT | FALSE | | | 15.655 | 14.450 | 0.000 | 0.000 | 14.450 | 14.450 |
| Port Townsend Paper Co. | 716 | 2003 | 2 | NT | FALSE | | | 15.854 | 15.854 | 0.000 | 0.000 | 15.854 | 15.854 |
| Port Townsend Paper Co. | 716 | 2003 | 3 | NT | FALSE | | | 15.852 | 14.536 | 0.000 | 0.000 | 14.536 | 14.536 |
| Port Townsend Paper Co. | 716 | 2003 | 4 | NT | FALSE | | | 16.044 | 14.712 | 0.000 | 0.000 | 14.712 | 14.712 |
| Port Townsend Paper Co. | 716 | 2003 | 5 | NT | FALSE | | | 16.270 | 2.506 | 0.000 | 0.000 | 2.506 | 2.506 |
| Port Townsend Paper Co. | 716 | 2003 | 6 | NT | FALSE | | | 16.245 | 14.214 | 0.000 | 0.000 | 14.214 | 14.214 |
| Port Townsend Paper Co. | 716 | 2003 | 7 | NT | FALSE | | | 16.323 | 14.968 | 0.000 | 0.000 | 14.968 | 14.968 |
| Port Townsend Paper Co. | 716 | 2003 | 8 | NT | FALSE | | | 15.654 | 13.040 | 0.000 | 0.000 | 13.040 | 13.040 |
| Port Townsend Paper Co. | 716 | 2003 | 9 | NT | FALSE | | | 15.617 | 14.320 | 0.000 | 0.000 | 14.320 | 14.320 |
| US DOE (Richland) | 404 | 1998 | 10 | NTP | TRUE | 34.494 | 34.494 | | | | | | |
| US DOE (Richland) | 404 | 1998 | 11 | NTP | TRUE | 31.570 | 37.446 | | | | | | |
| US DOE (Richland) | 404 | 1998 | 12 | NTP | TRUE | 44.201 | 47.697 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 1 | NTP | TRUE | 38.997 | 41.114 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 2 | NTP | TRUE | 33.174 | 40.478 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 3 | NTP | TRUE | 31.843 | 36.825 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 4 | NTP | TRUE | 33.163 | 45.190 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 5 | NTP | TRUE | 36.144 | 57.038 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 6 | NTP | TRUE | -5.394 | 34.500 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 7 | NTP | TRUE | 33.649 | 34.500 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 8 | NTP | TRUE | 32.564 | 2.348 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 9 | NTP | TRUE | 30.412 | 32.849 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 10 | NTP | TRUE | 26.765 | 33.952 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 11 | NTP | TRUE | 30.322 | 34.352 | | | | | | |
| US DOE (Richland) | 404 | 1999 | 12 | NTP | TRUE | 31.333 | 38.953 | | | | | | |
| US DOE (Richland) | 404 | 2000 | 1 | NTP | TRUE | 35.862 | 40.736 | | | | | | |
| US DOE (Richland) | 404 | 2000 | 2 | NTP | TRUE | 34.143 | 39.091 | | | | | | |
| US DOE (Richland) | 404 | 2000 | 3 | NTP | FALSE | | | 32.125 | 33.841 | 0.000 | | 29.263 | 32.125 |
| US DOE (Richland) | 404 | 2000 | 4 | NTP | FALSE | | | 39.517 | 40.178 | 0.000 | | 29.485 | 39.517 |

# Appendix D Table 2

Generating Publics and Other's Sales-related Load Data (Megawatts)

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer | CustNo | Year | Month | Choice | History | Actual Base | Actual Load Shaping | Forecasted System Load, Nominal | Forecasted System Load, CP | Contract CSL, Nominal | Internal Gen-eration, Nominal | Forecast Base | Forecast Load Shaping |
| US DOE (Richland) | 404 | 2000 | 5 | NTP | FALSE | | | 46.016 | 42.176 | 0.000 | | 26.726 | 46.016 |
| US DOE (Richland) | 404 | 2000 | 6 | NTP | FALSE | | | 31.619 | 27.419 | 0.000 | | -4.287 | 31.619 |
| US DOE (Richland) | 404 | 2000 | 7 | NTP | FALSE | | | 36.646 | 41.091 | 0.000 | | 40.078 | 36.646 |
| US DOE (Richland) | 404 | 2000 | 8 | NTP | FALSE | | | 2.398 | 2.638 | 0.000 | | 36.587 | 2.398 |
| US DOE (Richland) | 404 | 2000 | 9 | NTP | FALSE | | | 31.291 | 30.490 | 0.000 | | 28.228 | 31.291 |
| US DOE (Richland) | 404 | 2000 | 10 | NTP | FALSE | | | 70.846 | 66.834 | 0.000 | | 59.997 | 70.846 |
| US DOE (Richland) | 404 | 2000 | 11 | NTP | FALSE | | | 74.497 | 74.497 | 0.000 | | 64.181 | 74.497 |
| US DOE (Richland) | 404 | 2000 | 12 | NTP | FALSE | | | 83.133 | 76.604 | 0.000 | | 66.555 | 83.133 |
| US DOE (Richland) | 404 | 2001 | 1 | NTP | FALSE | | | 84.103 | 85.629 | 0.000 | | 78.390 | 84.103 |
| US DOE (Richland) | 404 | 2001 | 2 | NTP | FALSE | | | 85.150 | 85.150 | 0.000 | | 72.136 | 85.150 |
| US DOE (Richland) | 404 | 2001 | 3 | NTP | FALSE | | | 32.228 | 33.950 | 0.000 | | 29.357 | 32.228 |
| US DOE (Richland) | 404 | 2001 | 4 | NTP | FALSE | | | 39.739 | 40.404 | 0.000 | | 29.651 | 39.739 |
| US DOE (Richland) | 404 | 2001 | 5 | NTP | FALSE | | | 46.405 | 42.532 | 0.000 | | 26.952 | 46.405 |
| US DOE (Richland) | 404 | 2001 | 6 | NTP | FALSE | | | 31.876 | 27.642 | 0.000 | | -4.322 | 31.876 |
| US DOE (Richland) | 404 | 2001 | 7 | NTP | FALSE | | | 36.980 | 41.466 | 0.000 | | 40.443 | 36.980 |
| US DOE (Richland) | 404 | 2001 | 8 | NTP | FALSE | | | 2.399 | 2.640 | 0.000 | | 36.612 | 2.399 |
| US DOE (Richland) | 404 | 2001 | 9 | NTP | FALSE | | | 31.298 | 30.497 | 0.000 | | 28.234 | 31.298 |
| US DOE (Richland) | 404 | 2001 | 10 | NT | FALSE | | | 71.239 | 67.204 | 0.000 | | 60.330 | 71.239 |
| US DOE (Richland) | 404 | 2001 | 11 | NT | FALSE | | | 74.987 | 74.987 | 0.000 | | 64.603 | 74.987 |
| US DOE (Richland) | 404 | 2001 | 12 | NT | FALSE | | | 83.683 | 77.111 | 0.000 | | 66.996 | 83.683 |
| US DOE (Richland) | 404 | 2002 | 1 | NT | FALSE | | | 84.162 | 85.689 | 0.000 | | 78.445 | 84.162 |
| US DOE (Richland) | 404 | 2002 | 2 | NT | FALSE | | | 85.426 | 85.426 | 0.000 | | 72.370 | 85.426 |
| US DOE (Richland) | 404 | 2002 | 3 | NT | FALSE | | | 32.331 | 34.059 | 0.000 | | 29.451 | 32.331 |
| US DOE (Richland) | 404 | 2002 | 4 | NT | FALSE | | | 39.963 | 40.632 | 0.000 | | 29.818 | 39.963 |
| US DOE (Richland) | 404 | 2002 | 5 | NT | FALSE | | | 46.797 | 42.891 | 0.000 | | 27.180 | 46.797 |
| US DOE (Richland) | 404 | 2002 | 6 | NT | FALSE | | | 32.135 | 27.867 | 0.000 | | -4.357 | 32.135 |
| US DOE (Richland) | 404 | 2002 | 7 | NT | FALSE | | | 37.317 | 41.843 | 0.000 | | 40.811 | 37.317 |
| US DOE (Richland) | 404 | 2002 | 8 | NT | FALSE | | | 2.401 | 2.642 | 0.000 | | 36.637 | 2.401 |
| US DOE (Richland) | 404 | 2002 | 9 | NT | FALSE | | | 31.305 | 30.503 | 0.000 | | 28.240 | 31.305 |
| US DOE (Richland) | 404 | 2002 | 10 | NT | FALSE | | | 71.633 | 67.576 | 0.000 | | 60.664 | 71.633 |
| US DOE (Richland) | 404 | 2002 | 11 | NT | FALSE | | | 75.479 | 75.479 | 0.000 | | 65.027 | 75.479 |
| US DOE (Richland) | 404 | 2002 | 12 | NT | FALSE | | | 84.237 | 77.622 | 0.000 | | 67.439 | 84.237 |
| US DOE (Richland) | 404 | 2003 | 1 | NT | FALSE | | | 84.221 | 85.749 | 0.000 | | 78.500 | 84.221 |
| US DOE (Richland) | 404 | 2003 | 2 | NT | FALSE | | | 85.702 | 85.702 | 0.000 | | 72.604 | 85.702 |
| US DOE (Richland) | 404 | 2003 | 3 | NT | FALSE | | | 32.435 | 34.168 | 0.000 | | 29.546 | 32.435 |
| US DOE (Richland) | 404 | 2003 | 4 | NT | FALSE | | | 40.188 | 40.860 | 0.000 | | 29.986 | 40.188 |
| US DOE (Richland) | 404 | 2003 | 5 | NT | FALSE | | | 47.193 | 43.254 | 0.000 | | 27.409 | 47.193 |
| US DOE (Richland) | 404 | 2003 | 6 | NT | FALSE | | | 32.397 | 28.094 | 0.000 | | -4.392 | 32.397 |
| US DOE (Richland) | 404 | 2003 | 7 | NT | FALSE | | | 37.657 | 42.224 | 0.000 | | 41.183 | 37.657 |
| US DOE (Richland) | 404 | 2003 | 8 | NT | FALSE | | | 2.403 | 2.644 | 0.000 | | 36.663 | 2.403 |
| US DOE (Richland) | 404 | 2003 | 9 | NT | FALSE | | | 31.311 | 30.510 | 0.000 | | 28.246 | 31.311 |

# Appendix D, Table D3

Some Determinants of Short-term PSW Sales */

| (A) | (B) | (C) | | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|
| /---------- Model Statistics ----------/ | | | | /---------- Coefficients ----------/ | | | | |
| **Regression Statistics** | | **Forecast Statistics** | | **Variable** | **Coefficient** | **StdErr** | **T-Stat** | **P-Value** |
| Iterations | 1.0 | Forecast Observations | 0.0 | Constant term | 803.353 | 555.386 | 1.446 | 14.89% |
| Adjusted Observations | 365.0 | Mean Abs. Dev. (MAD) | 0.0 | CAPACITY | 0.111 | 0.034 | 3.301 | 0.11% |
| Deg. of Freedom for Error | 352.0 | Mean Abs. % Err. (MAPE) | 0.00% | PRICESCMMC | 58.412 | 15.623 | 3.739 | 0.02% |
| R-Squared | 0.5 | Avg. Forecast Error | 0.0 | TEMPSPSW | 15.496 | 3.117 | 4.972 | 0.00% |
| Adjusted R-Squared | 0.4 | Mean % Error | 0.00% | **LTCTRCTINT** | **-0.442** | 0.222 | -1.993 | 4.70% |
| Durbin-Watson Statistic | 0.5 | Root Mean-Square Error | 0.0 | OCTNOV | -171.870 | 217.902 | -0.789 | 43.08% |
| Durbin-H Statistic | #NA | Theil's Inequality Coefficient | 0.0 | DECJAN | -433.151 | 203.559 | -2.128 | 3.40% |
| AIC | 12.1 | -- Bias Proportion | 0.00% | FEBMAR | -650.560 | 186.569 | -3.487 | 0.06% |
| BIC | 12.3 | -- Variance Proportion | 0.00% | APRMAY | -710.825 | 110.246 | -6.448 | 0.00% |
| F-Statistic | 25.7 | -- Covariance Proportion | 0.00% | JUNJUL | -482.382 | 81.328 | -5.931 | 0.00% |
| Prob (F-Statistic) | 0.0 | | | TUEWEDTHR | 233.290 | 54.616 | 4.271 | 0.00% |
| Log-Likelihood | -2,714.1 | | | MONFRI | 109.525 | 53.380 | 2.052 | 4.09% |
| Model Sum of Squares | 56,044,091 | | | SAT | 90.363 | 77.950 | 1.159 | 24.72% |
| 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 | | | | | | | |

*/ 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/

| CUSNO | CUSTOMER | (A) Current | (B) Choice Base | (C) Choice Economic | (D) Agent /2 |
|---|---|---|---|---|---|
| 102 | Albion, City of | NT | NT | NT | PBL |
| 301 | Alder Mutual Light Co. | NT | NT | NT | |
| 103 | Ashland, City of | NTP | NT | NT | |
| 201 | Asotin County PUD #1 | NT | NT | NT | PBL |
| 104 | Bandon, City of | NTP | NT | NT | |
| 203 | Benton Cnty PUD | PTP | NT | NT | |
| 303 | Benton REA | NT | NT | NT | |
| 306 | Big Bend Electric Coop. | NT | NT | NT | PBL |
| 309 | Blachly-Lane County Coop. | NT | NT | NT | PNGC |
| 106 | Blaine | NTP | NT | NT | |
| 107 | Bonners Ferry (City) | NTP | NT | NT | |
| 109 | Burley, City of | NT | NT | PTP | PBL |
| 111 | Canby Utility Board | NTP | NT | NT | |
| 115 | Cascade Locks, City of | NTP | NT | NT | |
| 312 | Central Elec Coop, Inc. | NT | NT | NT | PNGC |
| 207 | Central Lincoln PUD | NT | NT | NT | |
| 313 | CENTRAL MONTANA ELECTRIC COOP | NT | NT | PTP | |
| 119 | Centralia, City of | NT | NT | NT | |
| 210 | Chelan County PUD #1 | NTP | STP | PTP | |
| 123 | Cheney, City of | NT | NT | NT | |
| 124 | Chewelah, City of | NT | NT | NT | PBL |
| 213 | Clallam County PUD #1 | NT | NT | NT | |
| 216 | Clark Public Utilities | NT | NT | NT | PPL |
| 219 | Clatskanie PUD | PTP | PTP | PTP | |
| 315 | Clearwater Power Co. | NT | NT | NT | |
| 318 | Columbia Basin Elec Coop | NT | NT | PTP | PBL |
| 321 | Columbia Power Coop | NT | NT | NT | PBL |
| 324 | Columbia REA | NT | NT | NT | PBL |
| 221 | Columbia River PUD | NT | NT | PTP | |
| 192 | Consolidated Irrigation Dist | NTP | NT | | |
| 327 | Consumer's Power, Inc. | NT | NT | NT | PNGC |
| 330 | Coos-Curry Electric Coop. | NT | NT | NT | PNGC |
| 125 | Coulee Dam (City of) | NT | NT | NT | PBL |
| 222 | Cowlitz County PUD | NTP | NT | PTP | |
| 127 | Declo, City of | NT | NT | NT | PBL |
| 226 | Douglas County PUD # 1 | PTP | PTP | PTP | |
| 333 | Douglas Electric Coop. | NT | NT | NT | PNGC |
| 128 | Drain, City of | NTP | NT | PTP | |
| 335 | East End Mutual Co. | NT | NT | NT | PBL |
| 131 | Eatonville, Town of | NT | NT | NT | |
| 133 | Ellensburg, City of | NT | NT | PTP | |
| 334 | Elmhurst Mutual | NT | NT | NT | |
| 229 | Emerald PUD | NTP | PTP | NT | |
| 841 | ENERGY NW INC., (FEC) | NT | NT | | |
| 137 | Eugene Water and Electric Board | NTP | PTP | NT | |
| 337 | Fall River Rural Elec Coop | NT | NT | NT | PBL |
| 338 | Farmers' Elec Company | NT | NT | NT | PBL |
| 230 | Ferry County PUD #1 | NT | NT | NT | PBL |
| 140 | Fircrest, City of | NT | NT | NT | |
| 339 | Flathead Electric Coop., Inc. | NTP | NT | NT | |
| 142 | Forest Grove, City of | NTP | NT | NT | |
| 233 | Franklin Cnty PUD | PTP | NT | NT | |

# Appendix E

Network "Choice" Analysis 1/

| CUSNO | CUSTOMER | (A) Current | (B) Choice Base | (C) Choice Economic | (D) Agent /2 |
|---|---|---|---|---|---|
| 340 | Glacier Electric Coop., Inc. | NT | NT | NT | |
| 238 | Grant County PUD #2 | NTP | PTP | PTP | |
| 241 | Grays-Harbor County PUD | PTP | PTP | PTP | |
| 341 | Harney Elec Coop, Inc. | NT | NT | NT | PBL |
| 150 | Heyburn, City of | NT | NT | PTP | PBL |
| 342 | Hood River Elec Coop | NT | NT | NT | PBL |
| 345 | Idaho County Light & Power | NT | NT | NT | |
| 152 | Idaho Falls, City of | PTP | PTP | PTP | |
| 348 | Inland Power & Light Co. | NT | NT | NT | |
| 246 | Kittitas County PUD #1 | NTP | NT | NT | |
| 250 | Klickitat Cnty | PTP | PTP | PTP | |
| 351 | Kootenai Electric Coop., Inc. | NT | NT | NT | |
| 353 | Lakeview Light & Power Co. | NT | NT | NT | |
| 354 | Lane Electric Coop., Inc. | NT | NT | NT | PNGC |
| 253 | Lewis County PUD #1 | NT | NT | PTP | |
| 357 | Lincoln Electric Coop. - MT | NT | NT | NT | |
| 358 | Lincoln Electric Coop.-WA | NT | | | |
| 359 | Lost River Elec Coop, Inc. | NT | NT | NT | PNGC |
| 360 | Lower Valley Power & Light | NT | NT | NT | |
| 257 | Mason County PUD #1 | NT | NT | NT | |
| 258 | Mason County PUD #3 | NT | NT | NT | |
| 154 | McCleary, City of | NT | NT | PTP | |
| 155 | McMinnville, City of | NT | NT | NT | |
| 361 | Midstate Elec Coop, Inc. | NT | NT | NT | PBL |
| 158 | Milton, City of | NT | NT | NT | |
| 159 | Milton-Freewater, City of | NT | NT | NT | |
| 161 | Minidoka, City of | NT | NT | NT | PBL |
| 364 | Missoula Electric Coop. | NT | NT | NT | |
| 366 | Modern Electric Co. | NT | NT | PTP | PBL |
| 163 | Monmouth, City of | NTP | NT | NT | |
| 817 | NATIONAL ENERGY SYSTEMS COMPANY | PTP | PTP | | |
| 367 | Nespelem Valley Elec. Coop. | NT | NT | NT | PBL |
| 370 | Northern Lights, Inc. | NT | NT | NT | PNGC |
| 262 | Northern Wasco County PUD | NT | NT | NT | |
| 372 | Ohop Mutual Light Co. | NT | NT | NT | |
| 373 | Okanogan County Elec. Coop. | NTP | NT | NT | PBL |
| 266 | Okanogan County PUD | NTP | NT | NT | |
| 376 | Orcas Power & Light Co. | NT | NT | NT | |
| 371 | Oregon Trail Elec Coop | NT | NT | PTP | PNGC |
| 270 | Pacific County PUD #1 | NT | NT | NT | |
| 375 | Parkland Light & Water Co. | NT | NT | NT | |
| 273 | Pend Oreille PUD #1 | NTP | NT | NT | |
| 374 | Peninsula Light Co., Inc. | NT | NT | NT | |
| 167 | Plummer, City of | NT | NT | NT | PBL |
| 170 | Port Angeles City Light | NT | NT | NT | |
| 716 | PORT TOWNSEND PAPER CORPORATION | NTP | NT | PTP | |
| 379 | Raft River Rural Elec Coop. | NT | NT | NT | PNGC |
| 380 | Ravalli County Electric Coop. | NTP | NT | NT | |
| 175 | Richland, City of | PTP | NT | NT | |
| 381 | Riverside Elec Company, Ltd. | NT | NT | NT | PBL |
| 177 | Rupert, City of | NT | NT | NT | PBL |
| 382 | Rural Elec Company | NT | | | PBL |

# Appendix E

Network "Choice" Analysis 1/

| CUSNO | CUSTOMER | (A) Current | (B) Choice Base | (C) Economic | (D) Agent /2 |
|---|---|---|---|---|---|
| 383 | Salem Electric | NT | NT | PTP | PBL |
| 384 | Salmon River Elec | NTP | NT | NT | |
| 180 | Seattle City Light | PTP | PTP | PTP | |
| 279 | Skamania County PUD | NT | NT | NT | PBL |
| 283 | Snohomish County PUD | PTP | PTP | PTP | |
| 181 | Soda Springs, City of | NT | NT | PTP | PBL |
| 385 | South Side Elec Lines, Inc. | NT | NT | NT | PBL |
| 184 | Springfield Utility Board | PTP | PTP | PTP | |
| 185 | Steilacom, Town of | NT | NT | NT | |
| 186 | Sumas, City of | NTP | NT | PTP | |
| 386 | Surprise Valley Elec. Corp. | NT | NT | NT | PBL |
| 188 | Tacoma Public Utilities | NTP | PTP | PTP | |
| 387 | Tanner Electric Coop. | NTP | NT | NT | |
| 288 | Tillamook People's Util. Dist. | NT | NT | NT | |
| 189 | Troy, City of | NTP | NT | NT | |
| 430 | U.S. AIR FORCE (FAIRCHILD) | NT | NT | PTP | PBL |
| 490 | U.S. DEPARTMENT OF NAVY (BANGOR) | NTP | NT | PTP | |
| 491 | U.S. DEPARTMENT OF NAVY (JIM CREEK) | NTP | NT | PTP | |
| 451 | U.S. DEPARTMENT OF NAVY (PUGET SOUN | NTP | NT | NT | |
| 482 | U.S.B.I.A.- Wapato | NT | NT | NT | PBL |
| 388 | Umatilla Elec Coop | NT | NT | NT | PNGC |
| 311 | UNITED ELECTRIC COOP | NT | NT | NT | PBL |
| 389 | Unity Light & Power | NT | | | PBL |
| 410 | US BUREAU OF MINES | NTP | NT | NT | |
| 405 | US DEPT OF ENERGY (300 AREA) | NTP | NT | PTP | |
| 404 | US DEPT OF ENERGY (RICHLAND) | NTP | NT | | |
| 499 | USBIA- Mission Valley | NT | NT | | |
| 483 | USBIA-MISSION VALLEY POWER | NT | NT | NT | |
| 498 | USBIA-Wapato | NT | NT | | |
| 472 | USBR, YAKIMA PROJECT (ROZA) | NT | NT | NT | |
| 695 | VANALCO | PTP | PTP | | |
| 191 | Vera Water & Power | NT | NT | NT | |
| 390 | Vigilante Electric Coop. | NT | NT | NT | |
| 293 | Wahkiakum County PUD | NT | NT | NT | |
| 394 | Wasco Elec Coop | NT | NT | NT | PBL |
| 195 | WASHINGTON PUBLIC POWER SUPPLY SYST | NTP | NT | NT | |
| 396 | Wells Rural Elec Company | NT | NT | PTP | |
| 397 | West Oregon Electric Coop. | NTP | NT | NT | |
| 298 | Whatcom County PUD #1 | NT | NT | NT | |

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), is the result of the economic analysis.

2/ Note: PBL's agency is assocated with the current rate period.

APPENDIX F

# FPT-02 Revenue Forecast

# Appendix F
## FPT-02 Revenue Forecast

| Company | Resource | POD Name | Contr No. | Demand (MW) POD | Demand (MW) Project | Wght | Main Grid Term1 | Main Grid Miles | Main Grid Misc | Main Grid Term2 | Main Grid Interc Term | Main Grid Txf | Secondary System Interc Term | Secondary System Interm Term 1 | Secondary System Miles | Secondary System Interm Term 2 | Priest Rapids | POD Rate Factors $/kW-yr | Compensation Factors $/kW-mo | Compensation Factors $/kW-yr | Project Revenues $000/yr |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Avista | WNP-3 | Westside | 92186 | 32.2 | 32.2 | 1.000 | 1.0 | 284.4 | 1.0 | 1.0 | 1.0 | | | | | | | 21.001 | 1.750 | 21.001 | 676.6 |
| | Avista System (GTA) | Colbert Tap | 91970 | 15.1 | 65.3 | 0.231 | | | | | | | 1.0 | 1.0 | 7.9 | | | 1.732 | | | |
| | | Deer Park | 91970 | 11.1 | 65.3 | 0.170 | | | | | | | 1.0 | 1.0 | 17.4 | | | 2.072 | | | |
| | | Loon Lake | 91970 | 4.4 | 65.3 | 0.067 | | | | | | | 1.0 | 1.0 | 22.3 | | | 0.984 | | | |
| | | Milan | 91970 | 7.7 | 65.3 | 0.118 | | | | | | | 1.0 | 1.0 | 15.4 | | | 1.314 | | | |
| | | 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 | | 1.702 | | | |
| | | Spirit | 91970 | 4.1 | 65.3 | 0.063 | | | | | | | 1.0 | 1.0 | 32.6 | | | 1.237 | | | |
| | | Wilbur | 91970 | 7.9 | 65.3 | 0.121 | | | | | | | | 1.0 | 18.0 | | | 1.332 | 0.864 | 10.372 | 676.8 |
| 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 | 12.835 | 1.070 | 12.835 | 218.3 |
| | Swift | Longview 69 | 92043 | 77.0 | 77.0 | 1.000 | | 21.4 | 1.0 | 1.0 | 0.5 | | | | | | | 4.948 | 0.412 | 4.948 | 380.7 |
| | Wanapum | Longview 69 | 00025 | 21.0 | 21.0 | 1.000 | 1.0 | 154.3 | 1.0 | 1.0 | 0.5 | | | | | | | 13.215 | 1.101 | 13.215 | 277.5 |
| Douglas Co PUD | Nilles Corner | Nilles Corner | 90066 | 1.9 | 1.9 | 1.000 | | | | | | | | | 12.4 | | | 6.134 | 0.511 | 6.134 | 11.7 |
| | Wells | Columbia 115 | 92389 | 4.7 | 4.7 | 1.000 | | | | | | 1.0 | 1.0 | | | | | 6.890 | 0.574 | 6.890 | 32.4 |
| Okanogan Co PUD | Wells | East Omak 115 | 90013 | 0.0 | 0.0 | 0.640 | | 72.0 | 1.0 | | | 1.0 | 1.0 | | | | | 8.908 | | | |
| | Wells | Tonasket 115 | 90013 | 0.0 | 0.0 | 0.360 | | 72.0 | 1.0 | | | 1.0 | | 1.0 | 20.3 | | | 8.855 | 1.480 | 17.763 | 0.0 |
| PacifiCorp | Centralia | Load Center | 09228 | 638.0 | 638.0 | 1.000 | 1.0 | 51.0 | 1.0 | 1.0 | 1.0 | | | | | | | 7.500 | 0.625 | 7.500 | 4,785.0 |
| | Clatsop | Clatsop | 14612 | 5.7 | 7.0 | 0.814 | 1.0 | 80.4 | 1.0 | 1.0 | | 1.0 | | | | | | 11.474 | | | |
| | | Astoria | 14612 | 1.3 | 7.0 | 0.186 | | | | | | | 1.0 | 1.0 | 57.9 | | | 5.982 | | | |
| | | Tillamook | 14612 | 0.0 | 7.0 | 0.000 | | | | | | | 2.0 | 1.0 | 67.3 | 1.00 | | 0.000 | 1.455 | 17.456 | 122.2 |
| | Colstrip | Flathead | 90168 | 14.0 | 140.0 | 0.100 | 1.0 | 136.8 | 1.0 | 1.0 | | | | | | | | 1.194 | | | |
| | | Trumbull | 90168 | 14.0 | 140.0 | 0.100 | 1.0 | 141.5 | 1.0 | | | | | | | | | 1.164 | | | |
| | | Lion Mt | 90168 | 15.0 | 140.0 | 0.107 | 1.0 | 126.9 | 1.0 | | | | | | | | | 1.156 | | | |
| | | Buckley | 90168 | 70.0 | 140.0 | 0.500 | 1.0 | 414.9 | 1.0 | 1.0 | | | | | | | | 14.015 | | | |
| | | Libby | 90168 | 1.0 | 140.0 | 0.007 | 1.0 | 172.3 | 1.0 | 1.0 | | 1.0 | | 1.0 | 12.3 | | | 0.197 | | | |
| | | Columbia Falls | 90168 | 13.0 | 140.0 | 0.093 | 1.0 | 172.3 | 1.0 | 1.0 | | 1.0 | | 1.0 | 12.3 | | | 2.561 | | | |
| | | Kalispell | 90168 | 13.0 | 140.0 | 0.093 | 1.0 | 172.3 | 1.0 | 1.0 | | 1.0 | | 1.0 | 12.3 | | | 2.561 | 1.904 | 22.848 | 3,198.7 |
| | Hermiston | Alvey | 94316 | 420.0 | 490.0 | 0.857 | 1.0 | 224.9 | 1.0 | | | | | | | | | 14.108 | | | |
| | | Buckley | 94316 | 70.0 | 490.0 | 0.143 | 1.0 | 70.0 | 1.0 | | | | | | | | | 1.071 | 1.265 | 15.179 | 7,438.2 |
| | Midpoint-Medford | Roundup | 94333 | 55.0 | 600.0 | 0.092 | 1.0 | 39.8 | 1.0 | 1.0 | | 1.0 | 1.0 | | | | | 1.212 | | | |
| | | Alvey | 94333 | 145.0 | 600.0 | 0.242 | 1.0 | 259.9 | 1.0 | | | | | | | | | 4.467 | | | |
| | | Alvey | 94333 | 241.0 | 600.0 | 0.402 | 1.0 | 224.9 | 1.0 | | | | | | | | | 6.611 | | | |
| | | McNary 69 | 94333 | 35.0 | 600.0 | 0.058 | | | 1.0 | | | 1.0 | 1.0 | | | | | 0.569 | | | |
| | | Santiam | 94333 | 40.0 | 600.0 | 0.067 | 1.0 | 182.0 | 1.0 | 1.0 | | | 1.0 | 1.0 | | | | 1.209 | | | |
| | | Albany | 94333 | 84.0 | 600.0 | 0.140 | 1.0 | 206.5 | 1.0 | 1.0 | | 1.0 | 1.0 | | | | | 3.201 | 1.439 | 17.269 | 10,360.8 |
| | Priest Rapids | Midway 230 | 90100 | 150.0 | 235.0 | 0.638 | | | 1.0 | | | | | | | | | 1.832 | | | |
| | | Outlook | 90100 | 85.0 | 235.0 | 0.362 | 1.0 | 22.1 | 1.0 | | | | | | | | | 1.710 | 0.295 | 3.542 | 831.9 |
| | PSW(DC)/PPL | Alvey | 94280 | 200.0 | 200.0 | 1.000 | 1.0 | 27.6 | 1.0 | | | | | | | | | 5.047 | 0.421 | 5.047 | 1,010.4 |
| | Swift | Troutdale | 92269 | 222.0 | 222.0 | 1.000 | | 28.9 | 1.0 | 1.0 | 0.5 | | | | | | | 5.382 | 0.448 | 5.382 | 1,193.5 |
| | Wanapum | Troutdale | 26811 | 269.0 | 269.0 | 1.000 | 1.0 | 149.0 | 1.0 | 1.0 | 0.5 | | | | | | | 12.909 | 1.076 | 12.909 | 3,473.3 |
| | Widco | Centralia | 92325 | 17.3 | 17.3 | 1.000 | 1.0 | 83.5 | 1.0 | 1.0 | 0.5 | | | | | | | 9.120 | 0.760 | 9.120 | 157.8 |
| Pend Oreille Co PUD | Boundary POI | Usk | 92488 | 36.0 | 36.0 | 1.000 | 1.0 | 49.0 | 1.0 | 0.5 | 0.5 | | | | | | | 6.834 | 0.570 | 6.834 | 246.2 |
| | Box Canyon | Newport | 90006 | 0.0 | 0.0 | 0.278 | | | | | | | | 1.0 | 2.1 | | | 0.870 | | | |
| | | Sacheen | 90006 | 0.0 | 0.0 | 0.066 | | 7.8 | | | | | | 1.0 | 13.9 | 1.00 | | 0.762 | | | |
| | | Metaline Falls | 90006 | 0.0 | 0.0 | 0.116 | | | | | | | | | | | | 0.000 | | | |
| | | Diamond Lake | 90006 | 0.0 | 0.0 | 0.043 | | | | | | | | | 8.3 | 1.00 | | 0.267 | | | |
| | | Usk | 90006 | 0.0 | 0.0 | 0.497 | 1.0 | | 1.0 | 1.0 | | 1.0 | | 1.0 | 13.9 | 1.00 | | 10.180 | 1.007 | 12.079 | 0.0 |
| PGE | Boardman Unit 1 | John Day | 92260 | 75.0 | 75.0 | 1.000 | 1.0 | 28.3 | 1.0 | 1.0 | 1.0 | | | | | | | 6.187 | 0.516 | 6.187 | 464.4 |
| | WNP-3 | Keeler | 92187 | 53.7 | 53.7 | 1.000 | 1.0 | 101.6 | 1.0 | 1.0 | 2.0 | | | | | | | 10.947 | 0.912 | 10.947 | 587.7 |

# Appendix F
## FPT-02 Revenue Forecast

| Company | Resource | POD Name | Contr No. | Demand (MW) POD | Demand (MW) Project | Wght | Main Grid Term1 | Main Grid Miles | Main Grid Misc | Main Grid Term2 | Main Grid Interc Term | Txf | Secondary System Interc Term | Secondary System Interm Term 1 | Secondary System Miles | Secondary System Interm Term 2 | Priest Rapids | POD Rate Factors $/kW-yr | Compensation Factors $/kW-mo | Compensation Factors $/kW-yr | Project Revenues $000/yr |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power Resources | Boardman | John Day | 94151 | 50.0 | 50.0 | 1.000 | 1.0 | 28.3 | 1.0 | 1.0 | | | | | | | | 5.667 | | | |
| Coop (PNGC) | | Slatt | 94151 | 0.0 | 50.0 | 0.000 | | | | | | | | | | | | 0.000 | 0.472 | 5.667 | 283.2 |
| Puget Sound P&L | WNP-3 | Maple Valley | 92185 | 32.2 | 32.2 | 1.000 | 1.0 | 69.4 | 1.0 | 1.0 | 2.0 | | | | | | | 9.084 | 0.757 | 9.084 | 292.5 |
| Tacoma PU | Priest Rapids | Cowlitz | 13512 | 71.1 | 71.1 | 1.000 | 1.0 | 128.5 | 1.0 | | | | | | | | -0.2370 | 10.646 | 0.887 | 10.646 | 756.8 |
| | Centralia | Cowlitz | 94304 | 0.0 | 0.0 | 1.000 | | 38.1 | 1.0 | 1.0 | | | | | | | | 5.654 | 0.471 | 5.654 | 0.0 |
| | NFP | John Day | 93936 | 49.3 | 49.3 | 1.000 | 1.0 | 130.0 | 1.0 | | | | | | | | | 10.970 | 0.914 | 10.970 | 540.2 |
| Total FPT.1 | | | | 2,672 | | | | | | | | | | | | | | | | | 32,134 |
| Total FPT.3 | | | | 733 | | | | | | | | | | | | | | | | | 5,882 |
| Total FPT | | | | 3,405 | | | | | | | | | | | | | | | | | 38,017 |

APPENDIX G

# DSI Delivery Charge Revenue

# Appendix G
## DSI Delivery Charge Revenue

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

1/ Excludes facilities projected to be sold
2/ O&M projections based upon the projected 3 year average levels as applied to the year the UFT components were last updated

APPENDIX H

# Monthly Transmission Revenue

# Appendix H

## Monthly Transmission Revenue
## FY 2002, ($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 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | **38,017** |
| 2 | Integration of Resources | IR-02 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | **68,315** |
| 3 | Network Transmission, Base | NT-02 | 5,055 | 5,112 | 6,142 | 6,373 | 6,354 | 5,157 | 4,650 | 4,249 | 4,068 | 4,476 | 4,587 | 4,199 | **60,421** |
| 4 | Network Transmission, Load Shaping | NT-02 | 2,238 | 2,289 | 2,692 | 2,766 | 2,790 | 2,269 | 2,023 | 1,911 | 1,836 | 1,917 | 1,978 | 1,848 | **26,556** |
| 5 | Point to Point, Long-term Contracts | PTP-02 | 12,644 | 12,555 | 12,555 | 12,560 | 12,560 | 12,833 | 12,856 | 12,960 | 12,988 | 12,825 | 12,661 | 12,661 | **152,657** |
| 6 | Point to Point, Daily Block 1 | PTP-02 | 402 | 269 | 400 | 1,372 | 646 | 784 | 544 | 545 | 681 | 840 | 585 | 406 | **7,474** |
| 7 | Point to Point, Daily Block 2 | PTP-02 | 635 | 710 | 1,351 | 3,496 | 1,886 | 2,424 | 1,984 | 2,098 | 2,176 | 2,509 | 2,344 | 1,221 | **22,834** |
| 8 | Point to Point, Hourly | PTP-02 | 797 | 799 | 1,408 | 3,858 | 2,203 | 2,569 | 2,099 | 2,139 | 2,357 | 2,677 | 2,375 | 1,338 | **24,620** |
| 9 | **Subtotal General Rates, Network** | | **30,632** | **30,595** | **33,408** | **39,285** | **35,300** | **34,897** | **33,017** | **32,763** | **32,968** | **34,105** | **33,391** | **30,534** | **400,894** |
| 10 | Southern Intertie, Long-term Contracts | IS-02 | 3,994 | 3,892 | 3,854 | 3,854 | 3,854 | 3,854 | 4,311 | 5,261 | 5,409 | 5,425 | 5,425 | 4,055 | **53,188** |
| 11 | Southern Intertie, Daily Block 1 | IS-02 | 169 | 114 | 103 | 462 | 39 | 151 | 274 | 63 | 147 | 646 | 382 | 223 | **2,775** |
| 12 | Southern Intertie, Daily Block 2 | IS-02 | 305 | 194 | 258 | 1,016 | 450 | 696 | 1,411 | 1,501 | 1,486 | 2,079 | 2,199 | 884 | **12,479** |
| 13 | Southern Intertie, Hourly | IS-02 | 158 | 104 | 123 | 498 | 188 | 297 | 605 | 569 | 599 | 939 | 912 | 393 | **5,385** |
| 14 | **Subtotal General Rates, Southern Intertie** | | **4,626** | **4,304** | **4,337** | **5,830** | **4,530** | **4,998** | **6,602** | **7,394** | **7,642** | **9,089** | **8,919** | **5,556** | **73,826** |
| 15 | Montana Intertie | IM-02 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 16 | Intertie East | IE-02 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 17 | Utility Delivery Charge | Delv | 767 | 763 | 911 | 894 | 914 | 807 | 756 | 700 | 649 | 675 | 678 | 646 | **9,161** |
| 18 | DSI Delivery Charge | Delv | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | **5,790** |
| 19 | **Subtotal General Transmission Rates** | | **36,507** | **36,145** | **39,139** | **46,492** | **41,227** | **41,183** | **40,858** | **41,339** | **41,741** | **44,352** | **43,470** | **37,219** | **489,672** |
| | **Other** | | | | | | | | | | | | | | |
| 20 | Annual Cost Rate | | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | **1,375** |
| 21 | Columbia Storage Power Exchange | | 24 | 24 | 24 | 24 | 24 | 24 | 21 | 21 | 21 | 21 | 21 | 21 | **268** |
| 22 | Fiber | | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | 1,292 | **15,500** |
| 23 | Fiber Depreciation | | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | **696** |
| 24 | Generation Integration | | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | 614 | **7,369** |
| 25 | Irrigation Pumping Power | | 0 | 0 | 0 | 0 | 0 | 0 | 129 | 258 | 258 | 258 | 258 | 129 | **1,288** |
| 26 | Nonfederal Participation Depreciation | | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | **3,335** |
| 27 | Operations and Maintenance | | 59 | 29 | 0 | 0 | 0 | 29 | 29 | 147 | 117 | 117 | 88 | 59 | **675** |
| 28 | Personal Communications Wireless | | 339 | 339 | 339 | 339 | 339 | 339 | 339 | 339 | 339 | 339 | 339 | 339 | **4,070** |
| 29 | Power Factor Penalty Charge | | 421 | 431 | 507 | 521 | 525 | 427 | 381 | 360 | 346 | 361 | 372 | 348 | **5,000** |
| 30 | Remedial Action Scheme | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | **597** |
| 31 | Reservation Fee | | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | **828** |
| 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** | | **4,641** | **4,621** | **4,668** | **4,682** | **4,686** | **4,618** | **4,697** | **4,922** | **4,879** | **4,894** | **4,876** | **4,693** | **56,877** |
| | **Ancillary** | | | | | | | | | | | | | | |
| 36 | Scheduling Control & Dispatch | | 3,825 | 3,763 | 4,149 | 5,270 | 4,457 | 4,534 | 4,492 | 4,576 | 4,658 | 5,027 | 4,873 | 3,987 | **53,609** |
| 37 | Generation Supplied Reactive | | 1,462 | 1,436 | 1,577 | 2,019 | 1,697 | 1,744 | 1,736 | 1,774 | 1,809 | 1,951 | 1,890 | 1,540 | **20,633** |
| 38 | Regulation & Frequency Response | | 1,378 | 1,365 | 1,659 | 1,703 | 1,553 | 1,398 | 1,206 | 1,178 | 1,095 | 1,182 | 1,219 | 1,102 | **16,038** |
| 39 | Energy Imbalance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 40 | Operating Reserves - Spinning | | 1,632 | 1,617 | 1,965 | 2,018 | 1,839 | 1,656 | 1,429 | 1,395 | 1,297 | 1,400 | 1,444 | 1,305 | **18,996** |
| 41 | Operating Reserves - Supplemental | | 1,632 | 1,617 | 1,965 | 2,018 | 1,839 | 1,656 | 1,429 | 1,395 | 1,297 | 1,400 | 1,444 | 1,305 | **18,996** |
| 42 | **Subtotal Ancillary Services** | | **9,927** | **9,798** | **11,313** | **13,028** | **11,386** | **10,988** | **10,291** | **10,319** | **10,155** | **10,959** | **10,868** | **9,238** | **128,273** |
| 43 | **Total Revenue FY 2002** | | **51,076** | **50,564** | **55,120** | **64,201** | **57,300** | **56,789** | **55,846** | **56,580** | **56,775** | **60,205** | **59,215** | **51,151** | **674,822** |

# Appendix H

## Monthly Transmission Revenue
## FY 2003, ($000)

| | FY 2003 Service | Schedule | (A) Oct-02 | (B) Nov-02 | (C) Dec-02 | (D) Jan-03 | (E) Feb-03 | (F) Mar-03 | (G) Apr-03 | (H) May-03 | (I) Jun-03 | (J) Jul-03 | (K) Aug-03 | (L) Sep-03 | (M) FY 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **General Transmission** | | | | | | | | | | | | | | |
| 1 | Formula Power Transmission | FPT-02 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | 3,168 | **38,017** |
| 2 | Integration of Resources | IR-02 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | 5,693 | **68,315** |
| 3 | Network Transmission, Base | NT-02 | 5,124 | 5,193 | 6,235 | 6,459 | 6,448 | 5,231 | 4,731 | 4,329 | 4,145 | 4,559 | 4,666 | 4,271 | **61,392** |
| 4 | Network Transmission, Load Shaping | NT-02 | 2,263 | 2,319 | 2,727 | 2,799 | 2,827 | 2,299 | 2,050 | 1,938 | 1,861 | 1,944 | 2,004 | 1,871 | **26,901** |
| 5 | Point to Point, Long-term Contracts | PTP-02 | 13,478 | 13,389 | 13,389 | 13,201 | 13,201 | 13,201 | 13,758 | 13,862 | 13,891 | 13,638 | 13,622 | 13,622 | **162,253** |
| 6 | Point to Point, Daily Block 1 | PTP-02 | 414 | 279 | 411 | 1,431 | 679 | 818 | 527 | 526 | 658 | 820 | 557 | 383 | **7,502** |
| 7 | Point to Point, Daily Block 2 | PTP-02 | 655 | 734 | 1,389 | 3,645 | 1,982 | 2,528 | 1,921 | 2,026 | 2,101 | 2,451 | 2,231 | 1,150 | **22,813** |
| 8 | Point to Point, Hourly | PTP-02 | 822 | 827 | 1,448 | 4,023 | 2,315 | 2,680 | 2,032 | 2,066 | 2,276 | 2,615 | 2,260 | 1,260 | **24,624** |
| 9 | **Subtotal General Rates, Network** | | **31,617** | **31,602** | **34,461** | **40,420** | **36,312** | **35,617** | **33,880** | **33,608** | **33,793** | **34,888** | **34,202** | **31,418** | **411,817** |
| 10 | Southern Intertie, Long-term Contracts | IS-02 | 4,006 | 3,904 | 3,865 | 3,633 | 3,633 | 3,633 | 3,633 | 4,215 | 4,248 | 4,226 | 4,226 | 3,800 | **47,023** |
| 11 | Southern Intertie, Daily Block 1 | IS-02 | 168 | 113 | 102 | 522 | 41 | 161 | 320 | 78 | 187 | 805 | 467 | 238 | **3,203** |
| 12 | Southern Intertie, Daily Block 2 | IS-02 | 303 | 193 | 256 | 1,148 | 474 | 741 | 1,648 | 1,861 | 1,881 | 2,589 | 2,688 | 943 | **14,725** |
| 13 | Southern Intertie, Hourly | IS-02 | 157 | 104 | 122 | 563 | 198 | 316 | 707 | 705 | 758 | 1,169 | 1,114 | 420 | **6,333** |
| 14 | **Subtotal General Rates, Southern Intertie** | | **4,634** | **4,313** | **4,345** | **5,867** | **4,346** | **4,851** | **6,309** | **6,860** | **7,074** | **8,788** | **8,496** | **5,402** | **71,284** |
| 15 | Montana Intertie | IM-02 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 16 | Intertie East | IE-02 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 17 | Utility Delivery Charge | Delv | 776 | 772 | 922 | 905 | 925 | 816 | 765 | 708 | 656 | 683 | 686 | 653 | **9,268** |
| 18 | DSI Delivery Charge | Delv | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | 483 | **5,790** |
| 19 | **Subtotal General Transmission Rates** | | **37,509** | **37,170** | **40,211** | **47,674** | **42,066** | **41,767** | **41,436** | **41,658** | **42,005** | **44,841** | **43,866** | **37,956** | **498,159** |
| | **Other** | | | | | | | | | | | | | | |
| 20 | Annual Cost Rate | | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | **1,375** |
| 21 | Columbia Storage Power Exchange | | 21 | 21 | 21 | 21 | 21 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | **127** |
| 22 | Fiber | | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | 1,458 | **17,500** |
| 23 | Fiber Depreciation | | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | **696** |
| 24 | Generation Integration | | 603 | 603 | 603 | 603 | 603 | 603 | 603 | 603 | 603 | 603 | 603 | 603 | **7,235** |
| 25 | Irrigation Pumping Power | | 0 | 0 | 0 | 0 | 0 | 0 | 129 | 258 | 258 | 258 | 258 | 129 | **1,288** |
| 26 | Nonfederal Participation Depreciation | | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | **3,335** |
| 27 | Operations and Maintenance | | 59 | 29 | 0 | 0 | 0 | 29 | 29 | 147 | 117 | 117 | 88 | 59 | **675** |
| 28 | Personal Communications Wireless | | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | 369 | **4,430** |
| 29 | Power Factor Penalty Charge | | 421 | 431 | 507 | 521 | 525 | 427 | 381 | 360 | 346 | 361 | 372 | 348 | **5,000** |
| 30 | Remedial Action Scheme | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | **597** |
| 31 | Reservation Fee | | 138 | 138 | 138 | 138 | 138 | 138 | 138 | 138 | 138 | 138 | 138 | 138 | **1,656** |
| 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** | | **4,892** | **4,873** | **4,919** | **4,933** | **4,938** | **4,869** | **4,926** | **5,151** | **5,107** | **5,123** | **5,105** | **4,922** | **59,755** |
| | **Ancillary** | | | | | | | | | | | | | | |
| 36 | Scheduling Control & Dispatch | | 3,979 | 3,923 | 4,320 | 5,473 | 4,598 | 4,639 | 4,595 | 4,642 | 4,715 | 5,117 | 4,950 | 4,109 | **55,062** |
| 37 | Generation Supplied Reactive | | 1,526 | 1,502 | 1,648 | 2,108 | 1,757 | 1,790 | 1,780 | 1,804 | 1,835 | 1,991 | 1,924 | 1,591 | **21,257** |
| 38 | Regulation & Frequency Response | | 1,345 | 1,333 | 1,620 | 1,664 | 1,517 | 1,366 | 1,178 | 1,151 | 1,069 | 1,154 | 1,190 | 1,076 | **15,663** |
| 39 | Energy Imbalance | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 40 | Operating Reserves - Spinning | | 1,538 | 1,524 | 1,852 | 1,901 | 1,734 | 1,561 | 1,347 | 1,315 | 1,222 | 1,319 | 1,361 | 1,230 | **17,903** |
| 41 | Operating Reserves - Supplemental | | 1,537 | 1,523 | 1,850 | 1,900 | 1,732 | 1,560 | 1,346 | 1,314 | 1,221 | 1,318 | 1,360 | 1,229 | **17,889** |
| 42 | **Subtotal Ancillary Services** | | **9,925** | **9,804** | **11,290** | **13,046** | **11,338** | **10,915** | **10,246** | **10,225** | **10,064** | **10,899** | **10,785** | **9,235** | **127,773** |
| 43 | **Total Revenue FY 2003** | | **52,326** | **51,847** | **56,420** | **65,653** | **58,342** | **57,551** | **56,607** | **57,035** | **57,176** | **60,863** | **59,755** | **52,112** | **685,687** |

APPENDIX I

# Power Factor Penalty Charge

# Appendix I
## 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.

Bonneville Power Administration

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DOE/BP-3321 AUGUST 2000 175