B o n n e v i l l e   P o w e r   A d m i n i s t r a t i o n
P o w e r   B u s i n e s s   L i n e

2003 Safety-Net Cost Recovery Adjustment Clause Initial Proposal

Study

Chapter 5 – Revenue Forecast

SN-03-E-BPA-01

March 2003

BONNEVILLE
POWER ADMINISTRATION

CHAPTER 5. REVENUE FORECAST

This chapter describes the revenue and purchased power expense forecasts prepared for BPA's SN CRAC initial rate proposal and the results of those forecasts.

5.1 Overview

The revenue and purchased power expense forecasts show BPA's expected levels of sales, revenues, purchases, and related expenses for the remainder of the current rate period — FY 2003-2006. BPA prepares two revenue forecasts: (1) one using current rates (*see* Table 5-1), and (2) one using proposed rates (*see* Table 5-2). These revenue forecasts are used to demonstrate that BPA's existing rates (*i.e.*, without the use of the SN CRAC) do not satisfy BPA's revenue recovery, and that BPA's proposed rates (with the use of the SN CRAC) satisfy BPA's revenue recovery. The revenue test is described in Chapter 3 of this Study, Revenue Requirements.

BPA's power rates placed into effect on October 1, 2001, as adjusted for the LB CRAC and the FB CRAC, are used in the calculation of revenues at current rates for FY 2003-2006. A projection of LB and FB CRAC percentage adjustments is used for future years. The proposed rates include the LB, FB, and the proposed SN CRAC percentages multiplied by the base rates. However, for purposes of this study, the LB CRAC is applied separately, while (for the purpose of calculating revenues where appropriate) the FB and SN CRAC percentages are added together and applied to the base rates. The proposed rates are applied to the loads subject to the SN CRAC for FY 2004-2006. Because the proposed SN CRAC does not apply in FY 2003, revenues for FY 2003 are the same in both forecasts. The SN CRAC reduces the net monetary benefits received by the IOUs under their Residential Exchange Program settlement agreements. The SN CRAC also reduces the net cost of the power sales and the power buybacks under the IOUs' Residential Exchange Program settlement agreements. The SN CRAC also reduces BPA's expenses under the LB CRAC for the RL load reductions. This impact is not reflected in forecast but will be reflected in the Final Proposal. The impact on RL load reductions reduces both augmentation expenses and the rates subject to the LB CRAC. BPA's revenue forecast also documents augmentation and other power purchases because these purchases support power sales.

5.2 Sources of BPA's Revenues

PBL revenues are divided into five groups. The first (and largest) source of revenue is from the sale of firm Subscription and pre-Subscription power to regional public agencies, Federal agencies, IOUs, and DSIs. Priority Firm (PF) power sales to full requirements customers, partial requirements customers, and PF block sales are all subject to the SN CRAC, but PF Slice sales, pre-Subscription sales, and Irrigation Mitigation sales are not subject to the SN CRAC. Industrial Firm (IP) power sales are subject to the SN CRAC, as are Residential Load (RL) and PF Exchange Subscription power sales to IOUs, RL power buybacks, and IOU monetary benefits.

A second revenue source is long-term contractual power sale obligations where the rates are already determined by contract or by contract formula outside of the Subscription or pre-Subscription process. These include several contracts with IOUs, municipalities, public agencies, and power marketers. These also include an extra-regional power sale to Bay Area Rapid Transit (BART), which is subject to the SN CRAC because the price in that contract is tied to the PF rate. No other long-term contractual obligation is subject to the SN CRAC.

A third major source of revenue is short-term energy sales where rates are determined in the market. This includes power sold on a monthly, weekly, daily or hourly basis. These sales are not subject to the SN CRAC.

A fourth source of revenue is from the generation inputs for ancillary and reserve products. The major component of this source is revenue from generation inputs provided to BPA's Transmission Business Line (TBL).

A final source of revenue is revenue credits from the U.S. Treasury and other miscellaneous revenues. Treasury credits include: section 4(h)(10)(C) credits, Fish Cost Contingency Fund (FCCF) credits, the Colville Settlement, downstream benefits credits from money paid to the U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation), revenues from the sale of Green Tags, and the Slice true-up. Revenues from 4(h)(10)(C) and FCCF credits were developed from runs of RiskMod and are documented in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 6. Other miscellaneous revenues include Energy Efficiency, contract administration fees, late fees, and interest on late payments.

5.2.1 Sales Subject to the SN CRAC

5.2.1.1 Priority Firm Power Sales. All PF sales are subject to the SN CRAC with the exception of PF Slice, sales to the Port of Seattle and Flathead Electric, and Irrigation Mitigation sales. Non-Slice PF sales in FY 2002 were 4,040 average megawatts (aMW). They are expected to be 4,022 aMW in FY 2003, and average 4,245 aMW during the FY 2004-2006 period. Of this latter amount, 4,112 aMW would be subject to the SN CRAC. As noted above, the non-Slice PF sales that are not subject to the SN CRAC are the 71 aMW of sales to the Port of Seattle and to Flathead Electric, and 62 aMW of Irrigation Mitigation sales (actually FPS sales that are grouped with PF sales). PF sales that are not subject to the SN CRAC also are not subject to the

FB CRAC. The revenues from the FB and SN CRACs are calculated and reported together in the revenue forecast.

PF revenues are calculated in stages. First, the revenues from PF sales are calculated by multiplying the appropriate May 2000 rates (either stepped or flat) by 1 plus the appropriate LB CRAC percentage, thereby determining the monthly HLH energy, LLH energy, demand, and load variance charges. Those charges are applied to the projected HLH energy, LLH energy, demand, and load variance billing quantities to obtain the corresponding monthly revenue components. The Low Density Discount (LDD) is then calculated using the appropriate discount percentage for each customer. Next, the Irrigation Mitigation revenues are added. The FB and SN CRAC revenues are calculated by adding the FB and SN CRAC percentages, multiplying that sum by the appropriate May 2000 rates, and multiplying the resulting products (for HLH energy, LLH energy, demand, and load variance) by the corresponding projected monthly billing quantities. Finally, the resulting revenues are summed and then multiplied by 1 minus the LDD percentage for each customer, to obtain the FB and SN CRAC revenues. These revenues were totaled and reported for each of the affected products: full requirements, partial requirements, and block sales.

5.2.1.2 Industrial Firm Power Sales. Industrial Firm Power (IP) sales were 65 aMW in FY 2002. These sales are projected to be 35 aMW in FY 2003, and are projected to average 350 aMW during the FY 2004-2006 period. All IP sales are subject to the SN CRAC. The revenues from the FB and SN CRACs for IP sales are calculated and reported together. The IP revenues were calculated by multiplying the May 2000 IP rate components by the appropriate LB CRAC percentage, and then multiplying that product by the forecasted billing quantities. The resulting amount represents the base revenues. The FB and SN CRAC revenues are calculated by adding the FB and SN CRAC percentages together, multiplying that sum by the appropriate IP rate components (*i.e.*, HLH energy, LLH energy, and demand), then multiplying those amounts by the projected monthly IP billing quantities. The resulting revenues are the FB and SN CRAC revenues. In the forecast of revenues at current rates that include the LB and the FB CRAC (shown on Table 5-1 at the end of this chapter) the process is exactly the same, but the SN CRAC percentage is left out.

The last step in calculating IP revenues is to estimate take-or-pay damages. Take-or-pay damages occur when IP purchases are curtailed and the power not purchased is sold in the surplus market. There are take-or-pay damages if the sum of the projected monthly losses during a fiscal year exceeds projected monthly gains from the sale of curtailed power deliveries at the market rate. If there are take-or-pay damages and there is a high likelihood that they will meet the revenue recognition criteria (*i.e.*, there is a high likelihood that they will be recovered during the accounting period), the damages are reported as revenue in the year they are earned. In the current revenue forecast, the IP rate adjusted for the LB and FB CRACs is less than the forecasted market rate of power. In the proposed revenue forecast, the IP rate adjusted for the LB, FB, and SN CRACs is higher than the forecasted market power rate.

5.2.1.3 Residential Load. Residential Load (RL) power sales to IOUs were 350 aMW in FY 2002, of which BPA bought back 113 aMW. Such sales are expected to be 382 aMW in FY 2003, of which BPA bought back 124 aMW, and are expected to average 382 aMW during the FY 2004-2006 period, of which BPA bought back 124 aMW. PacifiCorp and Puget Sound Energy (Puget) signed load reduction agreements that total 618 aMW over the period FY 2004-2006. The load reduction agreements require BPA to pay PacifiCorp and Puget for their portion of the original 1,000 aMW of power sales not purchased. Originally the cost was $45.49 per MWh for all 5 years, but BPA agreed with PacifiCorp and Puget that the utilities would agree to reduce the rate to $38.00 per MWh if litigation challenging their Subscription settlement agreements was settled. The difference in these rates over 5 years is approximately $200 million. PacifiCorp and Puget deferred collection of the difference between $45.49 and $38.00 pending settlement discussions. Further agreements with PacifiCorp and Puget have continued to defer this difference until at least the start of FY 2004. With implementation of an SN CRAC, load reduction payments to PacifiCorp and Puget would be reduced, but those reduced payments have not been reflected in this proposal. This is discussed in the testimony of Wedlund, *et al*., SN-03-E-BPA-09 Section 8.

In BPA's 2002 rate filing, the IOUs also received 900 aMW of monetary benefits that are subject to the SN CRAC. IOU monetary benefits are reduced by the product of the SN CRAC percentage and the lowest firm power rate ($19.76/MWh), and that adjusted rate is multiplied by 900 aMW and the hours in the year. In total, IOU loads affected by the SN CRAC total 1,900 aMW over the period FY 2004-2006, but only the effect on 1,282 aMW has been reflected in the forecast of revenues at proposed rates. The additional revenue from the IOU power buybacks is also estimated to be the SN CRAC percentage multiplied by the RL flat rate of $19.76 per MWh, multiplied by the 124 aMW of IOU buybacks. This is included in the 382 aMW RL sales, while the expense associated with the buyback is kept at $38.00/MWh. The revenues from RL sales are calculated by multiplying the appropriate LB CRAC percentage plus 1 by the appropriate RL rate components filed in May 2000 (*i.e.*, HLH energy, LLH energy, and demand). The resulting adjusted rates are multiplied by the HLH energy, LLH energy, and contract billing quantities. These revenues are added to the revenues from the FB and SN CRACs.

There are two components of SN CRAC revenues from the IOUs. The first is RL power deliveries including the sales associated with the power buybacks. The second is 900 average megawatts of monetary benefits. FB revenues also apply to the RL deliveries associated with sales and power buybacks.

The FB and SN CRAC revenues associated with RL power sales are calculated by adding the FB and SN CRAC percentages together, multiplying that sum by the RL rate components filed in May 2000, and multiplying that product by the forecasted RL billing quantities.

The SN CRAC revenues associated with the 900 aMW of monetary benefits are calculated by multiplying the SN CRAC percentage by $19.76 (the flat RL rate), and multiplying that product by the 900 MW of monetary benefits. Both components make up the FB and SN CRAC revenues associated with the RL rate. In the forecast of revenues at current rates shown on Table 5-1 (without the SN CRAC), the SN CRAC is set equal to zero and there are no revenues associated with RL power buybacks or IOU monetary benefits.

5.2.1.4 Long-Term Power Sales. The power sale to BART was 40 aMW in FY 2002. The power sale is expected to be 38 aMW in FY 2003, and is expected to average 30 aMW during the FY 2004-2006 period. The BART contract expires in FY 2006. The revenue from this contract is calculated by multiplying the appropriate LB CRAC percentage plus 1 by the contract rate components, and multiplying those adjusted rate components by the billing quantities. The FB and SN CRAC revenue is calculated by adding the LB, FB, and SN CRAC percentages to one, multiplying that sum by the BART contract rate components, and multiplying that rate by the billing quantities. In the forecast of revenues at current rates shown in Table 5-1, the SN CRAC percentage is set to zero.

In total, the SN CRAC is applied to 5,775 aMW of power deliveries, IOU power buybacks, and monetary benefits.

5.2.2 Power Sales Not Subject To SN CRAC. Sales not subject to the SN CRAC include: (1) pre-Subscription sales, which totaled 926 aMW in FY 2002, are expected to total 922 aMW in FY 2003, and are expected to average 948 aMW during the period FY 2004-2006; (2) PF Slice sales, which totaled 2,012 aMW in FY 2002, are expected to total 1,873 aMW in FY 2003, and are expected to average 2,206 aMW during the period FY 2004-2006; (3) SN CRAC revenues are not collected from sales made to the Port of Seattle and Flathead Electric, which total 71 aMW during the period FY 2004-2006; (4) Irrigation Mitigation sales totaling 62 aMW made to full, partial requirements, and block sales customers at the FPS rate but reported with PF full and partial requirements sales; (5) most long-term contractual sales either inside or outside of the region, which totaled 790 aMW in FY 2002, are expected to total 595 aMW in FY 2003, and are expected to average 339 aMW over the FY 2004-2006 rate period; and (6) short-term power sales, which are expected to average 2,569 aMW over the period FY 2004-2006. In total, the SN CRAC is not applied to 6,196 aMW of projected power sales during the period FY 2004-2006.

5.2.3 Other Revenues Not Subject To the SN CRAC. Just as some sales are not subject to the SN CRAC, none of the Treasury credits, revenues from ancillary and reserve product sales, or miscellaneous revenues are subject to the SN CRAC. Treasury credits are primarily for that portion of fish program expenses that are the responsibility of the non-power users of the FCRPS. Fish Cost Contingency Fund (FCCF) credits were provided to BPA in the 1990s to reimburse BPA for fish and wildlife expenses that should have been covered by non-power users of the FCRPS. Most of the remaining FCCF credits (originally $325 million) are expected to be nearly exhausted in FY 2003, with some remaining for FY 2004-2006. There is a small and continuing credit for payments to the Colville tribe and a similar small credit for payments to the Corps and the Reclamation from owners of downstream projects. Revenues from the sale of ancillary and reserve products are not subject to the SN CRAC and are expected to remain constant at about $81 million a year. Ancillary and reserve products and services are described in more detail below (*see* Section 5.4.7). Revenues from energy efficiency and miscellaneous sources are projected to be about $14 million per year.

5.3 Load Forecasts

The load forecasts used in BPA's revenue forecast are described in Chapter 2 of this study and are documented in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 2. Both current and proposed rates are applied to these loads. The firm load forecast is discussed in the testimony of Hirsch, *et al*., SN-03-E-BPA-05. This includes pre-Subscription sales, all categories of PF sales, IP sales, RL sales, and long-term contractual sales. The firm loads at current rates are assumed to be the same as the firm loads at proposed rates for the purpose of this rate proposal.

Because the forecast of firm loads is the same, the forecast of surplus power sales and revenue is the same at both existing and proposed rates. The forecast of surplus sales and revenue is described in Chapter 4 of this study and in the testimony of Oliver, *et al*., SN-03-E-BPA-08. This assumption simplifies and minimizes the number of studies and analyses needed for this proposal.

5.4 Revenue Forecast Methodology

5.4.1 Revenues from Priority Firm Sales. PF power sales are the largest source of FB and SN CRAC revenue. Revenues from PF power sales are calculated by multiplying the appropriate PF rates with the corresponding billing determinants (HLH energy, LLH energy, Load Variance, and demand). The LDD is also incorporated as it applies to specific customers. Loads and billing determinants were developed for each specific customer. The forecast of revenues at current rates (Table 5-1) and the forecast of revenues at proposed rates (Table 5-2) were based on those load forecasts, after increasing the rates by the appropriate LB CRAC percentage that was forecasted to recover projected augmentation expenses. The FB and SN CRAC revenues are determined by adding the FB and SN CRAC percentages together, multiplying that sum by the appropriate PF rate components, and multiplying those adjusted rates by the appropriate billing determinants. These revenues are reported by sales category on a monthly basis. *See* Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

As mentioned above, FB and SN CRAC percentages do not apply to PF Slice or Irrigation Mitigation rates. Customers that chose a PF stepped-rate are charged a different rate than customers that chose a flat rate. There is no load variance charge for PF Block power. The billing determinants for the loads were developed on a customer-by-customer basis, but are reported in summary form. *See* Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

Revenues from proposed rates were calculated in the same manner as revenues from current rates, except that the SN CRAC percentage was added to the FB CRAC percentage and applied to the applicable base rates. Consequently, there is an amount attributable just to the sum of the FB and SN CRACs. Annual summaries of these revenues at both current and proposed rates can be found in Tables 5-1 and 5-2 at the end of this chapter, and monthly summaries, which show the FB and SN CRAC revenues, are contained in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.4.2 Revenues from Sales to Investor Owned Utilities. Power deliveries and monetary benefit agreements with the IOUs provide the second largest source of FB and SN CRAC revenues. The revenues from RL sales, including those associated with power buybacks, are determined by applying HLH energy, LLH energy, and demand charges, increased by the projected LB CRAC percentage, to the corresponding contracted HLH energy usage, LLH energy usage, and contract demand quantities. In the forecast of revenues at current rates in Table 5-1, FB CRAC revenues were calculated by multiplying the FB CRAC percentage by the base rates, and multiplying that product by the appropriate billing determinants. In the forecast of revenues at proposed rates, the FB and SN CRAC revenues were calculated by adding those percentages together, multiplying that sum by the base rates, and multiplying those rates by the appropriate billing determinants.

The revenue adjustment to the IOU monetary benefits was calculated by multiplying the SN CRAC percentage by the flat RL rate ($19.76/MWh), and multiplying that amount by the total MWh associated with the 900 aMW of IOU monetary benefits for each month of the FY 2004-2006 period. The resulting amounts were added to the RL revenues in the proposed rate forecast.

The reduction in expenses associated with 618 aMW of IOU load reductions from PacifiCorp and Puget were not estimated. They can be estimated by calculating the amount that the sum of the FB and SN CRAC percentages from the base case in any month exceeds the maximum amount of FB percentage for that month, multiplying that difference by $19.76 (the lowest firm power rate), and multiplying that adjusted rate by 618 aMW and the number of hours in the year. This is about $30 million per year. If this amount was subtracted from BPA's augmentation expenses in the forecast of revenues at proposed rates, then the LB CRAC percentages for FY 2004-2006 would have been reduced, and the revenues recovered from the LB CRAC would have been reduced. That reduction in revenues subject to the LB CRAC would have exactly offset the reduction in augmentation expenses. Annual summaries of RL sales and revenues at both current and proposed rates can be found in the tables at the end of this chapter. Monthly summaries showing the revenues from the changes in monetary benefits are contained in the proposed rate forecast in Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.4.3 Revenues from Sales to DSIs. Revenues from DSIs are increased by the SN CRAC. Sales made at the IP TAC A and IP TAC B rates are subject to the SN CRAC. DSI customers may curtail their purchases from BPA, but those curtailments are subject to a take-or-pay charge. Take-or-pay charges are based on the difference between the market price of energy and the average price that could be received from sales at the applicable IP rate, multiplied by the amount of energy curtailed during a particular period of time. For BPA's May 2000 Proposal, this forecast of revenues at current rates assumed that the market price of energy is high enough relative to the IP rate that there is no exposure to take-or-pay charges. At the proposed IP rate, take-or-pay charge obligations are likely to be incurred.

5.4.4 Take-or-Pay Charges at Proposed Rates. The forecast of revenues at proposed rates assumes that BPA does not reflect any take-or-pay charges from Golden Northwest, Kaiser, or Longview Aluminum because there is only a small likelihood that those damages are recoverable during the FY 2004-2006 time period. This forecast further assumes that Columbia Falls Aluminum will exercise its one-time contract option to reduce its IP purchases to a very low level without a penalty, thereby avoiding take-or-pay charges. Annual summaries of these sales and revenues at both current and proposed rates can be found in Tables 5-1 and 5-2 at the end of this chapter. Monthly revenue summaries are contained in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.4.5 Revenues from pre-Subscription Sales. Revenues from pre-Subscription sales and long-term contracts were calculated on a contract-by-contract basis and summarized as a group for the hub to which those customers are assigned, as reflected in the tables at the end of this chapter. Currently, customers are assigned to one of three hubs: Bulk, East, and West. The Bulk hub includes the IOUs, DSIs, extra-regional long-term contracts, and short-term sales. The East and West hubs include public and Federal agency customers. Customers with pre-Subscription contracts are assigned to either the East or the West hubs. Pre-Subscription contracts were signed prior to the May 2000 rate proposal and are not subject to the LB, FB, or SN CRACs, with the exception of BART. Annual summaries of these sales and revenues at both current and proposed rates can be found in the tables at the end of this chapter. Monthly summaries are contained in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.4.6 Revenues from PF Slice Sales. Revenues from PF Slice sales were calculated using the Slice share associated with each participating customer. The Slice rate was adjusted for the forecasted LB CRAC percentage increase. Slice customers are subject to an annual true up instead of the FB CRAC, and estimates of these annual true-ups are recorded separately in Tables 5-1 and 5-2 at the end of this chapter. The Slice true-ups are consistent with the forecast of BPA's expenses contained in this proposal and, hence, the Slice rate is not subject to the SN CRAC. Revenues from Seasonal and Irrigation Mitigation sales are not subject to the LB, FB, or SN CRACs, as provided in the GRSPs.

5.4.7 Revenue From Secondary Energy Sales. Revenues from secondary energy sales are based on forecasted market supply and demand conditions. These sales include both committed and forecasted amounts. The committed sales are based on confirmation agreements, and the remaining secondary energy sales are a forecast of supply under various conditions and market prices. The development of the market price forecast and the short-term sales revenue forecast are described in Chapter 4 of this Study and the testimony of Oliver, *et al*., SN-03-E-BPA-08. The expected value sales, prices, and revenues represent a 50-year average and are documented in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 4.

5.4.8 Revenues from Ancillary and Reserve Product Sales. Revenues from ancillary and reserve product sales are estimated on a product-by-product basis and are summarized in the tables at the end of this chapter. These revenues are derived almost entirely from TBL. BPA sells several ancillary and reserve products, which are discussed below.

5.4.8.1 Federal Remedial Action Scheme. This is an annual charge that compensates PBL for TBL's share of the annual cost of Generation Dropping for the AC Intertie. The total annual cost, $293,500 was established in PBL's 2002 power rate case. It was determined that TBL's share of the total cost was $231,470, and TBL is billed in 12 equal monthly amounts.

5.4.8.2 Generation Supplied Reactive Power. This is an annual charge PBL collects from TBL to compensate for the reactive power and voltage control FCRPS generation facilities provide to the transmission system. In its 2002 power rate case, PBL identified FCRPS generation-related components that are used in the production of both real and reactive power. These components, referred to collectively as "electrical plant" are the generator stator and rotor, exciters, voltage regulators, certain power plant equipment, step-up transformers and generation integration facilities. Also included is 50 percent of accessory electrical equipment. Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the cost of electrical plant is allocated to the generation input for reactive power and voltage control. PBL also allocated the cost of real power losses associated with the flow of reactive power in the generation equipment to the generation input charge, as well as the costs associated with synchronous condensing (both plant modifications and energy costs). PBL determined that the total average annual cost to provide this generation input for Reactive Power and Voltage Control was $25 million.

5.4.8.3 Station Service. TBL obtains station service for many of its facilities directly off the BPA transmission system. The power supplied directly off the BPA system is all supplied by PBL. The purpose of this charge is to compensate PBL for the amount of station service being directly supplied by PBL for use at BPA substations. There are very few locations on the BPA system where station service usage is metered. Because of this, a methodology was developed in PBL's 2002 rate case to estimate the amount of kWh usage for each BPA substation. This methodology was based on the amount of primary station service transformation installed at each substation location multiplied by a load factor associated with average substation service usage. An overall average (weighted by transformer capacity) load factor of 904 percent was used for calculating station service usage. The system station service usage was estimated to be 6,432,205 kWh-month, or an average of 8.8 aMWs. PBL then applied a rate of 22.19 mills/kWh, the average PF rate, to arrive at a total annual cost of $1.7 million for station service.

5.4.8.4 Regulating Reserves. In its 2002 power rate case, PBL developed a methodology to allocate the costs of FCRPS to provide regulating reserves to the control area. Regulating reserves are produced by the generation capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulating reserves are required to provide AGC response to load and generation fluctuations in an effective manner. In order to maintain desired compliance with specific performance criteria, PBL estimates TBL's share of the total control area requirement to be 149 aMW. The established input cost for regulating reserves was determined to be $6.50 kW-mo. This input cost includes the costs of the 10 largest FCRPS hydro projects, plus an AGC adder to account for lost efficiency and increased operation and maintenance costs due to the provision of this service. Regulating reserves may be provided only by the ten largest plants and, therefore, the cost of this service is based solely upon the costs of these plants. The costs of the largest 10 plants include a share of fish and wildlife costs and associated generation integration and step-up transformer costs. The methodology excluded all other hydro assets, CGS, non-performing assets, conservation, the Residential Exchange Program settlements, and the costs associated with providing generation-supplied reactive and voltage control. The revenue requirement associated with the regulating reserve generation input was calculated by taking TBL's share of the annual average regulating reserve requirement for the control area (149 aMW * 12 * 1,000), multiplied by $6.50kW-month, which equals forecasted annual revenues of $11.5 million owed by TBL to PBL.

5.4.8.5 Operating Reserves. Operating reserves are the unloaded generating capacity, interruptible load, or other on-demand rights that the control area is able to fully deploy within 10 minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to 1 hour. Operating reserves include both spinning reserves and supplemental operating reserves. The WECC Minimum Operating Reliability Criteria require that each control area maintain an operating reserve equal to at least 5 percent of all hydro and 7 percent of all thermal and other non-hydro on-line generation within the control area. The per unit input cost for operating reserves was developed by calculating the unit cost of all FCRPS hydro projects, including fish and wildlife, generation integration, and step-up transformer costs. This methodology excludes the costs of CGS, non-performing assets, conservation, and the Residential Exchange Program settlements.

5.4.8.6 Spinning Reserves. Spinning reserves, a part of operating reserves, are the unloaded generating capacity of a system's firm resources that are synchronized to the power system and provide additional energy as required to be immediately responsive to system frequency. The WECC requires that each control area maintain spinning reserves equal to a minimum of 50 percent of its operating reserve obligation. The per-unit cost for spinning reserves was calculated to be $5.63 kW-month. The revenue requirement associated with the spinning reserve generation input was calculated based on an annual average spinning reserve requirement for the control area of 263 aMW (263 aMW * 12 * 1,000), multiplied by $5.63 kW-month, which equals forecasted annual revenues of $17.5 million owed by TBL to the PBL.

5.4.8.7 Supplemental Reserves. In its 2002 power rate case, PBL developed the unit cost associated with supplemental reserves. Supplemental reserves are that portion of the operating reserves that do not meet the definition of spinning reserves. Generally, supplemental reserves are that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. The per-unit cost for supplemental reserves was calculated to be $5.63 kW-month. The revenue requirement associated with the supplemental reserve generation input was calculated based on an annual average supplemental reserve requirement for the control area of 263 aMW (263 aMW * 12 * 1,000), multiplied by $5.63 kW-month, which equals forecasted annual revenues of $17.5 million owed by TBL to PBL.

5.4.8.8 Corps/Reclamation Network/Delivery Facilities. This is a cost assigned to TBL for transmission facilities owned by the Corps and Reclamation. The Corps and Reclamation own transmission facilities associated with their respective generating projects. In its 2002 power rate case, PBL included all the Corps and Reclamation costs in the generation revenue requirement, including the costs functionalized to transmission. Therefore, the Corps and Reclamation transmission investment costs were identified and segmented so that the annual costs of the transmission facilities were allocated to TBL. The total annual costs of these facilities assigned to TBL are $3.6 million in FY 2004-2005 and $3.5 million in FY 2006.

5.4.8.9 Reserve Services. Reserve Services are forecasted sales of ancillary services to third parties. The information used to create this forecast is deemed market sensitive and cannot be shared, but reserve services amount to less than $4 million per year paid by other parties to PBL.

5.4.9 Energy Efficiency and Miscellaneous Revenues. Revenues from the sale of Energy Efficiency services are roughly equal to expenses for each year of the rate period. Energy Efficiency revenues are forecasted to be slightly more than $9 million per year. Revenues from Green Tag sales are projected to be less than $1 million per year during the period FY 2004-2006. Miscellaneous revenues are generally comprised of late fees, contract administration fees, and interest for late bills, and are projected to be between $3-4 million per year.

5.4.10 Revenue Credits. BPA receives several revenue credits each year. The Colville credit is set by legislation at $4.6 million per year. The Corps and Reclamation credits are based on an estimate of receipts expected from owners of downstream projects. The FCCF credits are based on an expected value analysis of water conditions. Because the current and future years could be among the 15 worst years on record, these credits may be accessed until they are exhausted. The 4(h)(10)(C) credits are equal to 22 percent of the operational and programmatic expenses associated with fish and wildlife programs. The 22 percent figure is the non-power share of the FCRPS fish and wildlife expenses for which BPA receives Treasury credits.

5.4.11 Slice True-Up Adjustment Forecast. The Slice True-Up Adjustment Charge is calculated after final audited actual financial data is available for the fiscal year. BPA calculates, or “trues-up,” the difference between the actual and forecasted expenses and credits of the Slice Revenue Requirement. This difference is the basis for the Slice True-Up Adjustment Charge, which is billed to Slice purchasers in the months following the end of a fiscal year. The Slice True-Up Adjustment Charge may be positive, indicating a payment from the Slice purchaser, or it may be negative, indicating a BPA credit back to the Slice purchaser. For purposes of the SN CRAC initial proposal, the revenues anticipated to be collected from Slice purchasers through the Slice True-Up Adjustment Charge were forecasted for the FY 2003-2006 period.

Revenues anticipated to be collected from Slice purchasers through the Slice True-Up Adjustment Charge were forecasted using Table D, Slice Product Costing and True-Up Table, 2002 GRSPs, September 2001, at 132-133. Table D contains the May 2000 Proposal forecasts of the amounts in the expense and credit line items comprising the Slice Revenue Requirement upon which the Slice rate was based. The Slice True-Up Adjustment Charge is calculated based on the difference between the expense and credit amounts forecasted in Table D and the actual expense and credit amounts that are tallied in any given fiscal year. To develop a forecast of what this difference will be in FY 2003-2006, BPA assumed the actual expense and credit amounts would be equal to the expense and credit amounts used for the SN CRAC Trigger Study, SN-03-PR-01). BPA assumed that the revenues anticipated to be collected from Slice purchasers through the Slice True-Up Adjustment Charge for FY 2003 would be collected through the billing process in FY 2004, and the revenues collected through the Slice True-Up Adjustment Charge for FY 2004 would be collected through the billing process in the appropriate year.

The Slice True-Up has some base assumptions that do not change to reflect actual events. One key assumption in the development of the forecast of Slice True-Up revenues is that no Energy Northwest bond refinancing activity was assumed for the FY 2003-2006 period. Therefore, for purposes of the Slice True-Up Adjustment forecast, there is no difference assumed between the Energy Northwest debt service expenses in the SN CRAC Trigger Study, SN-03-PR-01, and the Energy Northwest debt service expenses in the May 2000 Proposal.

Another key assumption is that the Minimum Net Required Revenues line item is assumed to be zero. Therefore, for purposes of the Slice True-Up Adjustment forecast, there is no difference assumed for this line item for FY 2003-2006.

The assumptions described above were made because of the uncertainty in forecasting these expense line items and the volatility of their effects on the Slice True-Up Adjustment Charge. The revenues anticipated to be collected through the Slice True-Up Adjustment Charge were calculated by multiplying the annual difference between the total forecasted Slice Revenue Requirement based on the SN CRAC Trigger Study, SN-03-PR-01, expense forecast and the forecast of the Slice Revenue Requirement forecasted in the May 2000 Proposal by .226 (22.6 percent Slice sales), and adding $2 million each year in Slice Implementation Expenses. Slice Implementation Expenses are those expenses incurred by BPA to implement the Slice product. Slice purchasers are obligated to pay 100 percent of Slice Implementation Expenses.

The table below (Table 5-A) shows the components of the revenues anticipated to be collected through the Slice True-Up Adjustment Charge:

Components of the Slice True-Up Revenues	**FY 03**	**FY 04**	**FY 05**	**FY 06**
Difference Between Total Forecasted Slice Revenue Requirement for SN CRAC Trigger Study and May 2000 Proposal Slice Revenue Requirement	+$104 million	+$250 million	+$326 million	+$288 million
22.6 percent paid by Slice purchasers	$23 million	$56 million	$74 million	$65 million
Slice Implementation Expenses	$2 million	$2 million	$2 million	$2 million
Revenues from True-Up Adjustment Charge	$25 million	$58 million	$76 million	$67 million

5.5 Augmentation and Other Power Purchases

5.5.1 Augmentation Purchases. Augmentation purchases include load reductions, power buybacks, and power purchases. There are four categories of load reductions included in the forecast: (1) PF load reductions; (2) RL load reductions; (3) IP load reductions; and (4) power marketer load reductions. The average annual augmentation expense associated with load reductions for the period FY 2004-2006 is $286 million. The PF load reductions end in FY 2003, but the other three types of load reductions continue through the rate period. Power buyback contracts were signed with PF Block purchasers and with three IOUs. The power buybacks with the publics expire in FY 2003, but the power buybacks with the IOUs extend through the remainder of the rate period. The average cost of the IOU power buybacks over the FY 2004-2006 period is $41 million per year.

There are three categories of power purchases for augmentation: those signed prior to August 1, 2000, those signed after August 1, 2000, and renewable resources. While some renewable power purchase expenses are included in augmentation, the cost of renewable power purchases is included in the renewable program cost line item and not with the augmentation expense in the forecast of revenues at current or at proposed rates. The average annual expense associated with these augmentation purchases (excluding renewable resources) is $427 million. All augmentation purchases are calculated on a contract-by-contract basis and summarized on an annual basis in the tables at the end of this chapter. A monthly summary of all types of augmentation purchases is contained in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.5.2 Other Power Purchases. Other power purchases can be divided into four groups: (1) committed purchases; (2) balancing purchases; (3) Port of Seattle and Flathead Electric purchases; and (4) renewable resource purchases for Slice customers. Committed purchases are those purchases for which confirmation agreements have already been signed and which are reflected in the load and resource balance. The average annual cost of currently committed purchases during the FY 2004-2006 period is $30 million. Balancing purchases are an expected value output of RiskMod and are discussed in Chapter 6 of this Study and the testimony of Conger, *et al.*, SN-03-E-BPA-07. Balancing purchases are expected to average $10 million per year over the FY 2004-2006 period. Power purchases for the Port of Seattle and Flathead Electric average 71 aMW, at an average annual cost of $28 million over the 3-year period. These purchases are identified separately from other committed purchases because they are entirely offset by revenues from these customers. Renewable resource purchases for Slice customers are identified but not reported with the other categories of power purchases because these costs are included with other renewable program expenses.

5.6 FY 2003 Revenue and Purchased Power Expenses

Forecasted revenue and purchased power expenses for FY 2003 include a mix of actual revenues through December and forecasted revenues for the remainder of the year. The actual revenues for the month of January were unavailable when the FY 2003 forecast was prepared. In that forecast, total FY 2003 revenue is projected to be $2,982 million and purchased power expenses are projected to total $1,039 million.

5.6.1 FY 2003 Revenues. Revenue from Subscription sales, pre-Subscription sales, Slice sales and LB CRAC true-ups to public agencies totaled $1,795 million. This reflects estimated deliveries (including Slice) of 6,817 aMW. Sales to regional IOUs at the RL (and PF Exchange Subscription) rate are expected to result in FY 2003 revenues of about $93 million on sales of 382 aMW. Revenues from sales to DSIs (including liquidated damages) are expected to be $16 million on sales of 35 aMW. Revenues from short-term power sales are projected to be about $565 million on sales of 1,833 aMW. Revenues from ancillary and reserve products are projected to total about $82 million, of which almost $80 million are expected from TBL. Revenues from Energy Efficiency programs, Green Tag sales, and miscellaneous sources are projected to total almost $15 million, and credits are projected to total $202 million. All of these revenues are documented in Table 5-1 at the end of this chapter and in monthly detail in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.6.2 FY 2003 Purchased Power Expenses. Load reduction augmentation expenses are projected to average $286 million in the forecast of revenues at current rates and at proposed rates over the period FY 2004-2006, corresponding to load reductions of 821 aMW. Augmentation power buyback expenses are projected to average $41 million for buybacks totaling 124 aMW. Augmentation power purchase expenses, net of renewable resources for augmentation, are expected to average $427 million. All of these expenses and quantities are documented in Table 5-1 at the end of this chapter and in monthly detail in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 5.

5.7 Revenues and Purchased Power Expenses for FY 2004-2006 at Current Rates

Forecasted revenues at current rates (*i.e.*, without the SN CRAC) for the period FY 2004-2006 are shown in Table 5-1 at the end of this chapter. Revenues at current rates are projected to be $2,918 million in FY 2004, $2,945 million in FY 2005, and $2,915 million in FY 2006. Total purchased power expenses are projected to be $873 million in FY 2004, declining to $884 million in FY 2005, and to $833 million in FY 2006.

5.7.1 Revenues From Power Sales To Publics, IOUs, and DSIs at Current Rates. Revenues from firm power sales to regional public agencies are expected to increase from $1,776 million in FY 2004 to $1,823 million in FY 2006, with sales growing from 7,392 aMW to 7,440 aMW over that same period. Revenues from the Slice true-up are projected to be $58 million in FY 2004, $76 million in FY 2005, and $68 million in FY 2006. Revenues from firm power sales to IOUs at the RL and PF Exchange Subscription rates are projected to be about $94 million per year on sales of 382 aMW. Revenues from firm power sales to DSIs are projected to average $102 million per year from sales of 350 aMW per year over this 3-year period.

5.7.2 Revenues From Long-Term Contractual Sales. Revenues from long-term contracts are projected to decline from $152 million on sales of 422 aMW in FY 2004, to $134 million on sales of 371 aMW in FY 2005, to $109 million on sales of 316 aMW in FY 2006. The single largest contract is a capacity sale to PacifiCorp. There is no net energy sale associated with this contract because energy delivered during HLH is returned during LLH.

5.7.3 Revenues From Secondary Energy Sales. Revenues from secondary energy sales are the most volatile of BPA's revenues due to the uncertainty of supply and market prices. In FY 2004, these revenues are projected to total $560 million on sales of 2,513 aMW. In FY 2005, short-term market sales revenues are projected to total $570 million on sales of 2,631 aMW. In FY 2006 these revenues are projected to total $545 million on sales of 2,563 aMW. Revenues from these sales are unaffected by the SN CRAC. The revenue forecast from short-term market sales is a mix of committed and forecasted sales. The forecasted sales, prices, and revenue are estimated using RiskMod, which is also used to estimate balancing purchases. These monthly sales, prices, and revenue projections are documented in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 4 and discussed in the testimony of Oliver, *et al*., SN-03-E-BPA-08.

5.7.4 Revenues From Ancillary and Reserve Products and Services. Revenues from ancillary and reserve products and services are forecasted to be $81 million per year during the FY 2004-2006 period. Revenues from energy efficiency programs and miscellaneous sources are forecasted to be $13 million per year during this entire period.

5.7.5 Revenues From Treasury Credits. Revenues from Treasury credits are forecasted to total $79 million in FY 2004, $78 million in FY 2005, and $77 million in FY 2006. Section 4(h)(10)(C) credits were the largest part of this and totaled $67 million per year during the period.

5.8 Revenues and Purchased Power Expenses for FY 2004-2006 at Proposed Rates

Forecasted revenues at proposed rates (*i.e.*, with the SN CRAC) for the period FY 2004-2006 are shown in Table 5-2 at the end of this chapter. Revenues at proposed rates are projected to be $3,243 million in FY 2004, $3,288 million in FY 2005, and $3,180 million in FY 2006. Total purchased power expenses are projected to be $849 million in FY 2004, declining to $834 million in FY 2005, and to $783 million in FY 2006.

5.8.1 Revenues From Sales to Publics, IOUs, and DSIs. Revenues from firm power sales to regional public agencies are expected to increase from $1,992 million in FY 2004 to $2,023 million in FY 2005, and then decrease to $1,982 million in FY 2006, with sales growing from 7,392 aMW to 7,440 aMW over that same period. Revenues from the Slice true-up are projected to be $58 million in FY 2004, $76 million in FY 2005, and $68 million in FY 2006. Revenues from firm power sales to IOUs at the RL and PF Exchange Subscription rates are projected to be about $150 million in FY 2004, $156 million in FY 2005, and $146 million in FY 2006 on sales of 382 aMW per year. The significant increase in RL revenues from the current rate forecast is due to increased rates for 382 aMW of sales and the additional revenues from the 900 aMW of monetary benefits. Revenues from firm power sales to DSIs are projected to be $124 million in FY 2004, $122 million in FY 2005, and $118 million in FY 2006, from sales of 350 aMW, or an average of $121.6 million over the 3-year period.

5.8.2 Revenues From Long-Term Contracts. Revenues from long-term contracts are projected to decline from $159 million on sales of 422 aMW in FY 2004, to $140 million on sales of 371 aMW in FY 2005, and decline further to $112 million on sales of 316 aMW in FY 2006. The single largest contract is a capacity sale to PacifiCorp. There is no net energy sale associated with this contract because energy delivered during HLH is returned during LLH.

Revenue from one long-term contract (BART) is affected by the SN CRAC, because it is tied to the PF rate.

5.8.3 Revenues From Secondary Energy Sales. Because BPA assumes firm loads are unchanged by the SN CRAC, revenues from secondary energy sales are the same as the current rate forecast. In FY 2004 these revenues are projected to total $560 million on sales of 2,513 aMW. In FY 2005, short-term market sales revenues are projected to total $570 million on sales of 2,631 aMW. In FY 2006, this revenue is projected to total $545 million on sales of 2,563 aMW. Revenues from these sales are unaffected by the SN CRAC. The revenue forecast for short-term market sales is a mix of committed and forecasted sales.

5.8.4 Revenues From Ancillary and Reserve Products and Services. Revenues from ancillary and reserve products and services are forecasted to be $81 million per year during the FY 2004-2006 period. Revenues from energy efficiency programs and miscellaneous sources are forecasted to be $13 million per year during this entire period. These revenues are the same as in the current rate forecast.

Revenues from Treasury credits are forecasted to total $79 million in FY 2004, $78 million in FY 2005, and $77 million in FY 2006. Section 4(h)(10)(C) credits were the largest part of this and totaled $67 million per year during the period. Revenues from Treasury credits are unaffected by the SN CRAC.

TABLE 5-1 Revenues at Current Rates

Summary of Sales and Revenues	FY2003		FY2004		FY2005		FY2006	
	($000)	aMW	($000)	aMW	($000)	aMW	($000)	aMW
WEST HUB								
PF Full Service	$221,146	827	$226,351	871	$232,590	884	$240,418	902
PF Partial Service	$172,567	640	$178,554	685	$180,314	696	$184,489	701
PF Block Sales	$412,102	1,600	$402,719	1,622	$414,031	1,627	$422,182	1,635
LBCRAC True-ups	$1,480	0	$0	0	$0	0	$0	0
PF SLICE	$406,682	1,430	$394,439	1,710	$393,060	1,665	$393,278	1,696
TOTAL WEST PF	$1,213,977	4,505	$1,202,064	4,889	$1,219,995	4,871	$1,240,368	4,935
Pre-Subscription	$71,734	335	$73,873	338	$74,232	340	$70,040	318
TOTAL WEST	$1,285,711	4,840	$1,275,937	5,227	$1,294,227	5,211	$1,310,407	5,252
EAST HUB								
PF Full Service	$140,009	555	$154,120	625	$157,343	635	$163,128	649
PF Partial Service	$64,442	214	$68,522	231	$66,009	216	$69,084	219
PF Block Sales	$45,050	170	$43,975	185	$44,299	182	$42,726	173
LBCRAC True-ups	$453	0	$0	0	$0	0	$0	0
PF SLICE	$126,079	443	$122,328	521	$121,900	508	$121,967	517
TOTAL EAST PF	$376,840	1,390	$388,945	1,561	$389,550	1,540	$396,886	1,559
Pre-Subscription	$107,689	587	$111,476	604	$113,695	616	$115,958	629
TOTAL EAST	$484,529	1,978	$500,421	2,165	$503,245	2,156	$512,844	2,187
BULK HUB								
DSI IP Sales	$10,763	35	$102,525	351	$101,942	350	$103,083	350
LBCRAC True-ups	($15)	0	$0	0	$0	0	$0	0
DSI Liquidated Damages Est.	$0	0	$0	0	$0	0	$0	0
NW Long Term contracts	$84,410	110	$69,903	102	$64,400	102	$61,709	102
SW Long-term contracts	$134,490	523	$83,370	320	$69,428	269	$47,070	214
Subscription Sales to IOUs (RL)	$93,579	382	$94,105	383	$93,477	382	$94,673	382
LBCRAC True-ups	($96)	0	$0	0	$0	0	$0	0
Committed Trading Floor Sales	$295,865	1,048	$18,628	73	$11,022	41	$11,022	41
Balancing Trading Floor Sales	$251,017	722	$541,142	2,440	$558,858	2,589	$533,981	2,522
Flat and Other Trading Floor Sales	$0	0	$0	0	$0	0	$0	0
Real-time Sales	$17,819	63	$0	0	$0	0	$0	0
Other Delivery Obligations	$0	596	$0	673	$0	672	$0	672
TOTAL BULK	$887,832	3,480	$909,753	4,343	$899,215	4,405	$851,538	4,283
OTHER REVENUE								
Total Ancillary and Reserves	$81,956	0	$81,127	0	$81,098	0	$81,025	0
4(h)(10)(c) credit	$123,671	0	$66,915	0	$66,745	0	$67,338	0
FCCF credit	$69,177	0	$2,942	0	$1,462	0	$774	0
Colville settlement	$4,600	0	$4,600	0	$4,600	0	$4,600	0
Corps & Bureau Credits	$4,703	0	$4,700	0	$4,700	0	$4,700	0
Slice True-Up	$25,000	0	$58,000	0	$76,000	0	$68,000	0
Green Tags	$1,212	0	$787	0	$764	0	$754	0
EE, Property Sales & Misc.	$12,419	0	$12,670	0	$12,670	0	$12,670	0
Aluminum Hedging	$926	0	$0	0	$0	0	$0	0
Total Miscellaneous	$323,664	0	$231,742	0	$248,039	0	$239,861	0
TOTAL REVENUE	**$2,981,737**	**10,297**	**$2,917,853**	**11,735**	**$2,944,725**	**11,771**	**$2,914,650**	**11,723**
check against monthly totals	**$2,981,737**	**10,297**	**$2,917,853**	**11,735**	**$2,944,725**	**11,771**	**$2,914,650**	**11,723**
PF Buyback for SLICE & Block	$19,026	32	$0	0	$0	0	$0	0
PF Reduction Ld Following	$8,793	24	$0	0	$0	0	$0	0
RL Reduction	$205,639	618	$273,724	618	$272,427	618	$272,427	618
RL Buyback	$41,940	137	$41,390	124	$41,277	124	$41,277	124
IP Load Reduction	$100,005	647	$2,091	51	$2,085	51	$2,085	44
IP Load Curtailment	$145,343	513	$214,399	798	$212,769	794	$214,290	801
Marketer Load Reduction	$29,642	150	$11,421	75	$13,518	169	$9,253	218
Augmentation Power Purchases Pre 8/00	$172,919	706	$167,994	673	$167,413	671	$117,301	455
Augmentation Power Purchases Post 8/01	$277,697	575	$296,725	649	$314,752	666	$311,514	682
Total Augmentation Costs	**$855,659**	**1440**	**$793,345**	**1446**	**$810,472**	**1461**	**$753,858**	**1261**
Augmentation without Renewables	**$835,961**	**1393**	**$774,702**	**1388**	**$772,546**	**1375**	**$715,068**	**1153**
Committed T.F. Purchases	$124,035	420	$35,855	140	$27,438	114	$27,044	114
Other committed Purchases (Elwah, etc.)								
Slice Renewables (included in Renewable Expenses)	$5,681	14	$5,545	15	$11,370	26	$11,424	26
Balancing Power Purchases	$28,351	75	$10,572	28	$6,278	18	$12,443	35
Port of Seattle/Flathead Sleeves	$24,776	63	$28,090	71	$28,080	71	$28,131	71
Total Other Purchases	**$182,843**	**571**	**$80,061**	**254**	**$73,165**	**229**	**$79,041**	**246**
Other Purchases without Renewables	**$177,162**	**557**	**$74,516**	**239**	**$61,795**	**203**	**$67,617**	**220**

Table 5-2 Revenues at Proposed Rates

Summary of Sales and Revenues	FY2003		FY2004		FY2005		FY2006	
	($000)	aMW	($000)	aMW	($000)	aMW	($000)	aMW
WEST HUB								
PF Full Service	$220,914	827	$272,458	871	$281,073	884	$274,695	902
PF Partial Service	$172,567	648	$215,288	685	$218,255	695	$211,122	701
PF Block Sales	$412,102	1,600	$485,220	1,622	$500,874	1,627	$483,054	1,635
LBCRAC True-ups	$1,480	0	$0	0	$0	0	$0	0
PF SLICE	$406,682	1,430	$394,439	1,710	$383,060	1,665	$393,278	1,698
TOTAL WEST PF	$1,213,746	4,505	$1,367,404	4,889	$1,383,262	4,871	$1,362,149	4,935
Pre-Subscription	$71,734	335	$73,873	338	$74,232	340	$70,040	318
TOTAL WEST	$1,285,480	4,840	$1,441,277	5,227	$1,457,494	5,211	$1,432,188	5,252
EAST HUB								
PF Full Service	$140,009	556	$185,637	625	$190,278	635	$186,575	649
PF Partial Service	$64,442	214	$78,399	231	$75,792	215	$76,217	219
PF Block Sales	$45,858	178	$52,859	185	$53,464	182	$48,797	173
LBCRAC True-ups	$453	0	$0	0	$0	0	$0	0
PF SLICE	$126,079	443	$122,328	521	$121,900	508	$121,967	517
TOTAL EAST PF	$376,840	1,390	$439,222	1,561	$441,433	1,540	$433,556	1,559
Pre-Subscription	$107,689	587	$111,476	604	$113,695	616	$115,958	629
TOTAL EAST	$484,529	1,978	$550,698	2,165	$555,128	2,156	$549,514	2,187
BULK HUB								
DSI IP Sales	$10,763	35	$116,686	351	$116,480	350	$112,365	350
LBCRAC True-ups	($15)	0	$0	0	$0	0	$0	0
DSI Liquidated Damages Est.	$0	0	$7,580	0	$5,630	0	$5,630	0
NW Long-Term contracts	$84,410	110	$69,983	102	$64,488	102	$61,709	102
SW Long-term contracts	$134,884	523	$89,315	320	$75,458	269	$50,194	214
Subscription Sales to IOUs (RL)	$93,579	382	$149,990	383	$155,682	382	$146,424	382
LBCRAC True-ups	($96)	0	$0	0	$0	0	$0	0
Committed Trading Floor Sales	$297,943	1,054	$18,628	73	$11,022	41	$11,022	41
Balancing Trading Floor Sales	$251,017	722	$541,142	2,440	$558,858	2,589	$533,981	2,522
Flat and Other Trading Floor Sales	$0	0	$0	0	$0	0	$0	0
Real-time Sales	$17,819	63	$0	0	$0	0	$0	0
Other Delivery Obligations	$0	596	$0	673	$0	672	$0	673
TOTAL BULK	$890,304	3,486	$993,323	4,343	$987,617	4,405	$921,324	4,283
OTHER REVENUE								
Total Ancillary and Reserves	$81,956	0	$81,127	0	$81,098	0	$81,025	0
4(h)(10)(c) credit	$123,671	0	$68,915	0	$66,745	0	$67,338	0
FCCF credit	$69,177	0	$2,942	0	$1,462	0	$774	0
Colville settlement	$4,600	0	$4,600	0	$4,600	0	$4,600	0
Corps & Bureau Credits	$4,702	0	$4,700	0	$4,700	0	$4,700	0
Slice True-Up	$25,000	0	$58,000	0	$76,000	0	$68,000	0
Green Tags	$1,212	0	$787	0	$764	0	$754	0
EE, Property Sales & Misc	$12,418	0	$12,670	0	$12,670	0	$12,670	0
Aluminum Hedging	$926	0	$0	0	$0	0	$0	0
Total Miscellaneous	$323,662	0	$231,742	0	$248,039	0	$239,861	0
TOTAL REVENUE	**$2,983,975**	**10,303**	**$3,217,040**	**11,735**	**$3,258,278**	**11,771**	**$3,142,887**	**11,723**
check against monthly totals	**$2,983,975**	**10,331**	**$3,217,040**	**11,735**	**$3,258,278**	**11,771**	**$3,142,887**	**11,723**
PF Buyback for SLICE & Block	$19,025	32	$0	0	$0	0	$0	0
PF Reduction Ld Following	$8,793	24	$0	0	$0	0	$0	0
RL Reduction	$205,639	619	$273,724	618	$272,427	619	$272,427	619
RL Buyback	$41,940	127	$41,390	124	$41,277	124	$41,277	124
IP Load Reduction	$100,005	647	$2,091	51	$2,085	51	$2,085	44
IP Load Curtailment	$146,343	513	$280,332	796	$275,522	794	$270,063	801
Marketer Load Reduction	$29,642	150	$11,421	75	$12,518	169	$9,253	218
Augmentation Power Purchases Pre 8/00	$172,919	706	$167,994	673	$167,413	671	$117,301	455
Augmentation Power Purchases Post 8/01	$277,697	575	$298,725	649	$314,752	666	$311,514	682
Total Augmentation Costs	**$855,659**	**1440**	**$793,345**	**1446**	**$810,472**	**1461**	**$753,858**	**1261**
Augmentation without Renewables	**$835,961**	**1393**	**$774,782**	**1388**	**$772,546**	**1375**	**$715,068**	**1153**
Committed T.F. Purchases	$106,835	371	$35,855	140	$27,438	114	$27,044	114
Other committed Purchases (Elwah, etc.)								
Slice Renewables (included in Renewable Expenses)	$5,681	14	$5,545	15	$11,370	26	$11,424	26
Balancing Power Purchases	$28,351	75	$10,572	28	$6,278	18	$12,443	35
Port of Seattle/Flathead Sleeves	$27,059	68	$28,090	71	$28,080	71	$28,131	71
Total Other Purchases	**$167,925**	**528**	**$80,061**	**254**	**$73,165**	**229**	**$79,041**	**246**
Other Purchases without Renewables	**$162,245**	**514**	**$74,516**	**239**	**$61,795**	**203**	**$67,617**	**220**