Financial Statements

Including Notes to Financial Statements and Report of Independent Auditors

October 28, 2004

BONNEVILLE
POWER ADMINISTRATION

Financial Statements

Combined Balance Sheets

Federal Columbia River Power System
As of Sept. 30 — thousands of dollars

Assets

	2004	2003
Utility plant		
Completed plant	$ 12,243,684	$ 11,873,798
Accumulated depreciation	(4,357,496)	(4,133,886)
	7,886,188	7,739,912
Construction work in progress	1,401,793	1,308,624
Net utility plant	9,287,981	9,048,536
Nonfederal projects		
Conservation	43,566	47,246
Hydro	146,210	146,210
Nuclear	2,222,104	2,181,182
Terminated hydro facilities	28,090	28,840
Terminated nuclear facilities	3,894,273	3,883,115
Total nonfederal projects	6,334,243	6,286,593
Decommissioning cost	164,000	126,000
IOU exchange benefits	606,539	—
Conservation, net of accumulated amortization of $946,322 in 2004 and $892,218 in 2003	337,355	374,443
Fish and wildlife, net of accumulated amortization of $142,465 in 2004 and $133,743 in 2003	116,910	128,337
Current assets		
Cash	654,242	503,026
Accounts receivable, net of allowance	91,517	146,768
Accrued unbilled revenues	158,074	190,416
Materials and supplies, at average cost	81,246	84,306
Prepaid expenses	331,383	288,068
IOU exchange benefits	381,720	—
Total current assets	1,698,182	1,212,584
Other assets	387,569	230,756
	$ 18,932,779	$ 17,407,249

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2004	2003
Capitalization and long-term liabilities		
Accumulated net revenues	$ 847,424	$ 343,748
Federal appropriations	4,339,288	4,607,476
Capitalization adjustment	2,056,131	2,124,697
Bonds issued to U.S. Treasury	2,461,800	2,521,554
Nonfederal projects debt	6,218,932	6,045,931
Decommissioning reserve	164,000	126,000
IOU exchange benefits	626,576	55,488
Accrued plant removal costs	105,270	147,174
Total capitalization and long-term liabilities	16,819,421	15,972,068
Commitments and contingencies (Notes 7 and 8)		
Current liabilities		
Current portion of federal appropriations	104,673	73,484
Current portion of bonds issued to U.S. Treasury	438,500	176,200
Current portion of nonfederal projects debt	234,896	240,662
Current portion of IOU exchange benefits	381,720	—
Accounts payable and other current liabilities	338,867	369,821
Total current liabilities	1,498,656	860,167
Deferred credits	614,702	575,014
	$18,932,779	$17,407,249

Combined Statements of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2004	2003	2002
Operating revenues			
Sales	**$2,973,496**	$ 3,328,277	$ 3,407,404
SFAS 133 mark-to-market	**89,452**	55,265	38,354
Miscellaneous revenues	**57,963**	53,678	49,571
U.S. Treasury credits for fish	**77,000**	174,884	38,400
Total operating revenues	**3,197,911**	3,612,104	3,533,729
Operating expenses			
Operations and maintenance	**1,211,802**	1,198,521	1,319,707
Purchased power	**582,129**	1,043,009	1,286,867
Nonfederal projects	**248,475**	119,534	230,175
Federal projects depreciation	**366,239**	350,025	335,205
Total operating expenses	**2,408,645**	2,711,089	3,171,954
Net operating revenues	**789,266**	901,015	361,775
Interest expense			
Interest on federal investment:			
Appropriated funds	**213,041**	212,391	258,195
Bonds issued to U.S. Treasury	**110,251**	166,598	151,997
Allowance for funds used during construction	**(38,441)**	(33,398)	(57,892)
Net interest expense	**284,851**	345,591	352,300
Net revenues	**504,415**	555,424	9,475
Accumulated net revenues (expenses), Oct. 1	**343,748**	(211,676)	(221,151)
Irrigation assistance	**(739)**	—	—
Accumulated net revenues (expenses), Sept. 30	**$ 847,424**	$ 343,748	$ (211,676)

The accompanying notes are an integral part of these statements.

Combined Statements of Changes in Capitalization and Long-Term Liabilities

Federal Columbia River Power System
Including current portions — thousands of dollars

	Accumulated Net (Expenses) Revenues	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2002	$(211,676)	$4,642,602	$2,770,441	$6,201,544	$2,407,238	$15,810,149
Increase in federal appropriations for construction	—	99,418	—	—	—	99,418
Repayment of federal appropriations for construction	—	(61,060)	—	—	—	(61,060)
Capitalization adjustment amortization	—	—	—	—	(67,703)	(67,703)
Increase in long-term debt	—	—	470,000	—	—	470,000
Repayment of long-term debt	—	—	(482,687)	—	—	(482,687)
Refinance of long-term debt	—	—	(60,000)	—	—	(60,000)
Net increase in nonfederal projects debt	—	—	—	99,288	—	99,288
Repayment of nonfederal projects debt	—	—	—	(14,239)	—	(14,239)
Decommissioning reserve	—	—	—	—	52,139	52,139
IOU exchange benefits	—	—	—	—	55,488	55,488
Accrued plant removal costs	—	—	—	—	6,197	6,197
Net revenues	555,424	—	—	—	—	555,424
Balance at Sept. 30, 2003	$ 343,748	$4,680,960	$2,697,754	$6,286,593	$2,453,359	$16,462,414
Increase in federal appropriations for construction	—	78,047	—	—	—	78,047
Repayment of federal appropriations for construction	—	(315,046)	—	—	—	(315,046)
Capitalization adjustment amortization	—	—	—	—	(68,566)	(68,566)
Increase in long-term debt	—	—	480,000	—	—	480,000
Repayment of long-term debt	—	—	(277,454)	—	—	(277,454)
Net increase in nonfederal projects debt	—	—	—	179,130	—	179,130
Repayment of nonfederal projects debt	—	—	—	(11,895)	—	(11,895)
Decommissioning reserve	—	—	—	—	38,000	38,000
IOU exchange benefits	—	—	—	—	952,808	952,808
Accrued plant removal costs	—	—	—	—	(41,904)	(41,904)
Net revenues	504,415	—	—	—	—	504,415
Irrigation assistance	(739)	—	—	—	—	(739)
Balance at Sept. 30, 2004	$ 847,424	$4,443,961	$2,900,300	$6,453,828	$3,333,697	$17,979,210

The accompanying notes are an integral part of these statements.

Combined Statements of Cash Flows

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2004	2003	2002
Cash from operating activities			
Net revenues	**$ 504,415**	$555,424	$ 9,475
Non-cash items:			
Depreciation	**294,975**	269,957	254,332
Amortization	**71,264**	77,610	78,047
Amortization of capitalization adjustment	**(68,566)**	(67,703)	(67,356)
Decrease (increase) in:			
Receivables and unbilled revenues	**87,594**	(38,144)	88,765
Materials and supplies	**3,061**	801	115
Prepaid expenses	**(43,316)**	(2,372)	(98,547)
Decrease (increase) in:			
Accounts payable and other current liabilities	**(30,954)**	26,396	(167,532)
Other	**(152,601)**	51,802	(6,399)
Cash provided by operating activities	**665,872**	873,771	90,900
Cash from investment activities			
Investment in:			
Utility plant (including AFUDC)	**(576,324)**	(535,211)	(544,922)
Nonfederal projects	**(47,650)**	(85,050)	(29,595)
Conservation	**(16,876)**	(25,458)	(25,344)
Fish and wildlife	**(5,849)**	(11,156)	(6,102)
Cash used for investment activities	**(646,699)**	(656,875)	(605,963)
Cash from borrowing and appropriations			
Increase in federal construction appropriations	**78,047**	99,418	168,583
Repayment of federal construction appropriations	**(315,046)**	(61,060)	(196,911)
Irrigation assistance	**(739)**	—	—
Increase in bonds issued to U.S. Treasury	**480,000**	470,000	390,000
Repayment of bonds issued to U.S. Treasury	**(277,454)**	(482,687)	(308,101)
Refinance of bonds issued to U.S. Treasury	**—**	(60,000)	—
Increase in nonfederal debt, net	**167,235**	85,050	29,595
Cash provided by borrowing and appropriations	**132,043**	50,721	83,166
Increase (decrease) in cash	**151,216**	267,617	(431,897)
Beginning cash balance	**503,026**	235,409	667,306
Ending cash balance	**$ 654,242**	$503,026	$235,409

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of General Accounting Policies

Principles of Combination

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) and the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan Facilities. BPA is the power marketing agency which purchases, transmits and markets power for the FCRPS. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. The costs of multipurpose Corps and Reclamation projects are assigned to specific purposes through a cost-allocation process. Only the portion of total project costs allocated to power is included in these statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect specific legislation and executive directives issued by U.S. government departments. (BPA is a unit of the Department of Energy; Reclamation and U.S. Fish and Wildlife are part of the Department of the Interior; and the Corps is part of the Department of Defense.) FCRPS properties and income are tax-exempt. All material intercompany accounts and transactions have been eliminated from the combined financial statements.

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51," which clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. As a Variable Interest Entity, Northwest Infrastructure Financing Corporation (NIFC) has been consolidated into BPA for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications were made to the fiscal years 2002 and 2003 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2004. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's power and transmission rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power and nonfirm energy and for transmission service. Statutory standards include a requirement that these rates be sufficient to assure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs.

After final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit. Action seeking such review must be filed within 90 days of the final FERC decision. The court of appeals may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's General Counsel that, if a rate were rejected, it would be remanded to BPA for reformulation.

BPA submitted to FERC a Power Rate Filing in fiscal year 2001 for fiscal years 2002 through 2006, and a Transmission and Ancillary Services Rate Filing in fiscal year 2003 for fiscal years 2004 through 2005. FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001) and granted final approval on July 21, 2003, 104 FERC 61,093 (2003). FERC granted final approval of BPA's Transmission and Ancillary Services rates on Sept. 23, 2003, 104 FERC 62,207 (2003).

BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every six months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of modified accumulated net revenues is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or forecasts a 50 percent or greater probability of missing a payment to the Treasury or another creditor. Some of these rate adjustment clauses are calculated initially on forward-looking estimates of market conditions, and adjustments are made after the fact when actual conditions are known. These subsequent adjustments result in an additional charge or rebate due to customers for any excess or shortfall of amounts initially charged to them.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46.0 percent for the first half of fiscal year 2002 compared to base rates, and 40.8 percent for the second half of fiscal year 2002. The LB CRAC percentage increase was revised to approximately 31.9 percent and 38.5 percent, respectively, for the six-month periods beginning Oct. 1, 2002, and April 1, 2003. The LB CRAC percentage increase was revised to approximately 21.3 percent and 24.6 percent, respectively, for the six-month periods beginning Oct. 1, 2003 and April 1, 2004.

The August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a rate increase of approximately 11 percent for fiscal year 2003 and approximately 12 percent for fiscal year 2004 for most of the requirements rates on top of the revised levels of the LB CRAC.

The SN CRAC did not trigger in fiscal year 2002 but did trigger in fiscal year 2003, requiring an expedited rate case and resulting in a rate increase that went into effect Oct. 1, 2003 through Sept. 30, 2004, of approximately 10 percent on top of the revised levels of the LB CRAC and SN CRAC. BPA submitted to FERC a separate power rate filing for SN CRAC in fiscal year 2003. FERC granted interim approval of the SN CRAC rate on Oct. 1, 2003, 105 FERC 61,006 (2003) and final approval on May 10, 2004, 107 FERC 61,138 (2004). The SN CRAC rate filing augments the power rates already approved for fiscal years 2002 through 2006.

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percentage of BPA's power costs in exchange for a fixed percentage of generation output. Settlement of any over or under collection occurs in the subsequent year. For the fiscal year 2003 settlement, BPA recognized a $30.4 million liability to be paid in fiscal year 2004. For the fiscal year 2004 settlement, BPA recognized a receivable of $10.1 million to be received in fiscal year 2005.

SFAS 71 Assets

Because of the regulatory environment in which BPA establishes rates, certain costs may be deferred and expensed in future periods under Statement of Financial Accounting Standards (SFAS 71), "Accounting for the Effects of Certain Types of Regulation."

In order to defer incurred costs under SFAS 71, a regulated entity must have the statutory authority to establish rates that recover all costs and rates so established must be charged to and collected from customers. Due to increasing competitive pressures, BPA may be required to seek alternative solutions in the future to avoid raising rates to a level that is no longer competitive. If BPA's rates should become market-based, SFAS 71 would no longer be applicable, and any costs deferred under that standard would be expensed in the Statement of Revenues and Expenses.

If BPA were to discontinue using SFAS 71 it would simultaneously write down the SFAS 71 assets and amortize the remaining Appropriations Capitalization Adjustment resulting in a $3.6 billion net extraordinary loss that would be reported in the Statement of Revenues and Expenses.

The SFAS 71 assets of $5.6 billion, shown in the following table, reflect an increase of $930 million from the prior year. Amortization of these costs aggregating $103 million, $84 million and $299 million in fiscal years 2004, 2003 and 2002 respectively, is reflected in the Statements of Revenues and

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2004	2003
Nonfederal projects:		
Conservation	**$ 43,566**	$ 47,246
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,894,273**	3,883,115
Decommissioning cost*	**51,200**	18,200
IOU exchange benefits	**988,259**	—
Conservation	**337,355**	374,443
Fish and wildlife	**116,910**	128,337
Settlements	**70,142**	105,313
Capital bond premiums	**26,486**	30,802
Additional retirement contributions	**13,200**	23,400
	$ 5,569,481	$ 4,639,696

*The decommissioning amount to be collected in future rates is net of amounts paid into the decommissioning trusts of $112.8 million and $107.8 million at Sept. 30, 2004 and 2003 respectively.

Expenses. BPA does not earn a rate of return on its SFAS 71 assets.

Utility Plant

Utility plant is stated at original cost. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. The costs of additions, major replacements and betterments are capitalized. Repairs and minor replacements are charged to operating expense. The cost of utility plant retired is charged to accumulated depreciation when it is removed from service. The removal costs less salvage is charged to the regulatory liability. Utility plant in the Statements of Cash Flows is reported net of the Regulatory Liability for Removal Costs and accumulated depreciation.

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are up to 20 years for conservation and 15 years for fish and wildlife.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) constitutes interest on the funds used for utility plant under construction. AFUDC is capitalized as part of the cost of utility plant and results in a non-cash reduction of interest expense. While cash is not realized currently from this allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from higher plant in-service and higher depreciation expenses. AFUDC is based on the monthly construction work in progress balance.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects and were 1.3 percent to 5.3 percent in fisal year 2004, 1.8 percent to 6.3 percent in fiscal year 2003, and 3.3 percent to 6.5 percent in fiscal year 2002.

Capitalization rates for other construction were approximately 5.3 percent in fiscal year 2004, 6.3 percent in fiscal year 2003, and 6.5 percent in fiscal year 2002. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

BPA adopted SFAS 143, "Accounting for Asset Retirement Obligations," on Oct. 1, 2002. SFAS 143 requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as a liability. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. FCRPS has certain tangible long-lived assets for which AROs are not measurable. An ARO will be required to be recorded when circumstances change. Assets that may require removal when no longer in service include the hydro projects and transmission facilities.

Regulation

Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense allowed in rates. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset under SFAS 71. BPA expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation.

Asset Retirement Obligations Activity

As of Sept. 30, 2004, the AROs for Washington Nuclear Project No. 1 (WNP-1), Columbia Generating Station (CGS) and Trojan are $164 million. (See Decommissioning and Restoration Costs in Note 7, Commitments and Contingencies.) A corresponding amount representing a regulatory asset is included in Decommissioning Cost in the Balance Sheet.

The table below presents the effects to the balances and activities in AROs for the accounting periods reported herein. A revision was made in the current year adjusting the accretion rate from the original model and calculation. BPA has funded $112.8 million at Sept. 30, 2004 for these AROs, which is being held in trust. The remaining amount will be collected in future rates.

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and Corps. Cash paid for interest was $420 million, $466 million and $484 million in fiscal years 2004, 2003 and 2002 respectively.

Non-cash transactions include changes in nonfederal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $179 million, $99 million and $259 million in fiscal years 2004, 2003 and 2002 respectively.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist of available-for-sale investments held by Energy Northwest and BPA accounts receivable. Energy Northwest invests exclusively in securities of the U.S. government and agencies.

BPA's accounts receivable are spread across a diverse group of public utilities, investor-owned utilities, power marketers, and others that are geographically located throughout the Western United States and Canada. The accounts receivable exposures result from BPA providing a wide variety of power products and transmission services. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. During fiscal year 2004, BPA experienced no

Asset Retirement Obligations Activity

For the years ended Sept. 30 — thousands of dollars

	2004	2003	Proforma 2002
Beginning Balance	**$ 126,000**	$129,900	$134,100
Activity:			
Expenditures	**(7,900)**	(7,000)	(9,100)
Accretion	**6,800**	3,100	3,100
Revisions	**39,100**	—	1,800
Ending Balance	**$ 164,000**	$126,000	$129,900

significant losses as a result of any customer defaults or bankruptcy filings.

The Transacting Risk Management Committee is responsible for BPA's credit policy. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure. In order to further reduce credit risk, BPA obtains credit support such as letters of credit and third-party guarantees from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Credit Risk from California

California power markets were in turmoil several years ago and experienced historically high power prices and volatility along with the continued uncertainty related to deregulation. Defaults by Pacific Gas & Electric (which filed for bankruptcy protection in April 2001) and Southern California Edison (which has established a creditor payment plan) in payments for energy and transmission to the California Independent System Operator (Cal-ISO) resulted in the Cal-ISO not paying its suppliers. In addition, the California Power Exchange (Cal-PX) has substantial outstanding payment obligations due from the California investor-owned utilities for day-ahead power exchanges. The Cal-PX filed for bankruptcy protection in March 2001.

BPA entered into certain power sales during fiscal year 2001 through the Cal-PX for which BPA has not yet been paid. In addition BPA sold power and related services to the Cal-ISO during fiscal year 2001 for which BPA has not yet been paid in full. BPA has recorded provisions for uncollectible receivables and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, BPA is continuing to pursue collection of amounts due in bankruptcy and other proceedings. Net exposure after the reserve is not significant.

Retirement Benefits

FCRPS employees are participants in either the Civil Service Retirement System (CSRS) or the Federal Employees Retirement System (FERS). Both FCRPS and its employees contribute a percentage of eligible employee compensation toward funding these defined post-retirement benefit plans. Based on the statutory contribution rates, agency retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 10.7 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS. However, the legislatively mandated contribution levels do not fully cover the cost to the federal government to provide the plan benefits. Therefore, the programs are considered under funded. Employees also may be participants in the Federal Employees Health Benefits Program (FEHB) and/or the Federal Employees' Group Life Insurance Program (FEGLI); these plans are similarly under funded.

In order to ensure that all post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed, FCRPS makes additional annual contributions to the U.S. Treasury. Because these costs are included in rates, the amount has been recorded as an SFAS 71 asset. FCRPS has a $13.2 million remaining liability as of Sept. 30, 2004, which is included in other current liabilities and deferred credits in the accompanying Balance Sheet representing the balance of deferred additional contributions from fiscal years 1998 through 2001. The liability is reduced as prior year's additional contributions are made. FCRPS expects to satisfy its prior year commitments for under funded post-retirement benefits by fiscal year 2007.

Deferred Credits

Advances on customer reimbursable projects are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or are recorded to revenue over the related useful lives of the assets if BPA retains title.

Deferred revenues for Third AC intertie capacity agreements are recognized over the estimated 49-year life of the related assets.

Derivative/SFAS 133 mark-to-market represents unrealized losses on derivatives. It increased in fiscal year 2004 due to bookout transactions.

Load diversification fees are payments by customers to BPA in consideration for a reduction in their contractually obligated power purchases from BPA. Deferred load diversification fees and other settlement payments for long-term agreements are recognized as revenue over the original contract terms (load diversification fee contracts generally correspond to the rate period ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019).

Up front leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020.

BPA terminated all remaining contracts with Enron for $99 million effective April 1, 2003. BPA is reimbursing the U.S. Treasury judgment fund through 2006 for payment of the settlement.

The table below summarizes deferred credits as of Sept. 30, 2004 and 2003.

Hedging and Derivative Instrument Activities

BPA's hedging policy (Policy) allows the use of financial instruments such as commodity futures, options and swaps to hedge the price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development. The Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under specific provisions included in the Policy.

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future

Deferred Credits

As of Sept. 30 — thousands of dollars

	2004	2003
Customer reimbursable projects	**$ 183,933**	$ 153,190
Third AC intertie capacity agreements	**119,546**	122,612
Derivative/SFAS 133 mark-to-market	**106,513**	26,994
Load diversification fees	**81,163**	86,742
Fiber optic leasing fees	**59,335**	65,341
Enron settlement	**54,000**	94,000
Deferred CSRS	**6,600**	13,200
Unearned option premium revenue	**3,597**	12,822
Other miscellaneous long-term liabilities	**15**	113
Total	**$ 614,702**	$ 575,014

electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2004 or 2003.

Purchased and Written Options

In fiscal year 2004, BPA purchased physical put options for the right to sell electricity at certain points in the future. With significant inventory risk due to currently unpredictable annual runoff, the put options allow BPA to hedge against falling prices without committing inventory and increasing the inventory risk.

In prior periods, BPA sold put options for the sale of electricity to BPA at certain points in the future. BPA intends to take delivery of power as a result of written put options that have been exercised. The megawatt-hour quantities that BPA sold and the premiums that BPA collected for the sales of these options were priced on market-based information and a mathematical model developed by BPA. This model makes certain assumptions based on historical and other statistical data. Actual future results could vary from estimates, which may require BPA to buy power at strike prices above market prices as a result of the exercised written put option obligations.

BPA records purchased and written options on a mark-to-market basis and includes unrealized gains and losses in operating revenues in the Statement of Revenues and Expenses.

The following table reflects the purchased and written options outstanding as of Sept. 30, 2004 and 2003.

Purchased and Written Options

As of Sept. 30

	2004	2003
Purchased options		
Outstanding	**196,800 MWh**	—
Average strike price	**$ 56.45**	—
Written options		
Outstanding	—	1,972,800 MWh
Average strike price	—	$ 40.33

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheets as of Sept. 30, 2004 and 2003. The carrying value reflected in the Balance Sheets approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed LIBOR interest rate swaps to help manage interest rate risk related to its long-term debt portfolio. In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for 10 years and receives a variable rate that changes weekly tied to LIBOR. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for 15 years and receives a variable rate that changes weekly tied to LIBOR. The net effect of the two swap transactions is essentially replacing variable rate debt with 3.3 percent fixed rate debt. The swap transactions do not qualify for special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. BPA recorded a $2.05 million fair value gain and a $7.9 million fair value loss in the Statements of Revenues and Expenses for fiscal years 2004 and 2003 respectively, related to the interest rate swap transactions.

Adoption of Statement 133 and Related Guidance

BPA adopted SFAS 133, "Accounting for Derivative Instrument and Hedging Activities," as amended, on Oct. 1, 2000. SFAS 133 requires that every derivative instrument be recorded on the Balance Sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," related Derivative Implementation Group (DIG) guidance, and SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." Collectively, these statements are referred to as "SFAS 133." Purchases and sales of forward electricity and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS 133. These transactions are excluded under SFAS 133 and therefore are not required to be fair valued in the financial statements.

For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2004, 2003 and 2002, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

On the date of adoption, Oct. 1, 2000, in accordance with the transition provisions of SFAS 133, BPA recorded a cumulative-effect adjustment of $168 million in net expense to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted mainly of transactions known as bookouts, that the FASB initially determined should be fair valued in net revenue (expense).

On June 29, 2001, the FASB issued guidance on Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Issue C15 provided additional guidance on the classification and application of SFAS 133 relating to purchases and sales of electricity utilizing forward contracts and options including bookout transactions. This guidance became effective as of July 1, 2001. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

In April 2003, the FASB issued SFAS 149, which amends financial accounting and reporting for derivative instruments, including the accounting treatment for certain forward power sales and purchase contracts. SFAS 149 is effective for new contracts transacted after July 1, 2003. The normal purchase and sales exception previously allowed for bookout transactions under DIG issue C-15 was effectively eliminated by SFAS 149 and related guidance. As of Sept. 30, 2004, BPA recorded a $51 million fair value unrealized gain related to power purchase and sale transactions impacted by SFAS 149.

BPA recorded a SFAS 133 fair value unrealized gain in the Statement of Revenues and Expenses related to its derivative portfolio (including physical power purchase and sale transactions and purchased options) of $89.4 million, $55.3 million and $38.4 million for fiscal years 2004, 2003 and 2002 respectively.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $158 million, $190 million and $93 million at Sept. 30, 2004, 2003 and 2002 respectively. For revenue purposes, BPA operates as two segments: the Power Business Line and the Transmission Business Line. The table in Note 9 reflects the revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing agency, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS and the payment of certain irrigation costs as discussed in Note 7.

Fish Credits

The Northwest Power Act of 1980 obligated the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and non-power purposes, on a reimbursement basis. The Act also specified that consumers of electric power, through their rates for power services "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects.

In the early 1990s, BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism whereby BPA reduces its cash payments to the U.S. Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes.

Prior to fiscal year 1995, over $325 million of credits had accrued since the Act passed in 1980. The Fish Cost Contingency Fund (FCCF) was established for credits earned by BPA but not applied prior to fiscal year 1995. The FCCF was only to be accessed under specified criteria. Since the establishment of the FCCF, BPA has applied for and taken an FCCF credit twice. The first time occurred in fiscal year 2001 when the Pacific Northwest experienced a severe drought. BPA accessed the fund again in fiscal year 2003 due to adverse hydro conditions and applied the remaining FCCF credits of $79 million, which depleted the fund.

BPA has taken 4(h)(10)(C) fish credits annually since fiscal year 1995.

Recent Accounting Pronouncements

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." In December 2003, FIN 46 was reissued as FIN 46R, which contained revisions to address certain implementation issues. FIN 46 clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The interpretation differentiates between an entity with a majority voting interest (the previous requirement under ARB No. 51) and entities that have controlling financial interest through other arrangements that may not involve any voting interests and how these types of entities (variable interest entities) may need to be consolidated. For non-public entities there is no distinction in effective dates for Variable Interest Entities (VIEs) and non-VIEs. The application of FIN 46 is required for all entities created before Dec. 31, 2003, by no later than the beginning of the first interim or annual reporting period beginning after Dec. 15, 2003. For entities created after Dec. 31, 2003, application of FIN 46 is required as of the date they first become involved with the respective entities. Northwest Infrastructure Financing Corporation (NIFC) is the FCRPS's only VIE as of Sept. 30, 2004. NIFC has been consolidated into the BPA financial statements for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), "Reporting Realized Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes," requires that revenues and expenses associated with non-trading energy activities that are "booked out" (not physically settled) be reported on a net basis. EITF 03-11 is effective for all derivative contracts that settle after Sept. 30, 2003, and does not require the reclassification of prior period amounts. Effective with the Oct. 1, 2003 adoption of EITF 03-11, the non-physical settlement of non-trading electricity derivative activities, formerly recorded on a "gross" basis in both operating revenues and purchased power expense, are now recorded on a "net" basis in operating revenues. This change which has no effect on margins, net revenue or cash flows, resulted in a $212 million decrease to both operating revenues and purchased power expense for fiscal year 2004. The determination of the sales and purchases of electricity that would have been reported on a net basis had EITF 03-11 been historically applied is not practicable. Prospective application of EITF 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts reported in comparative financial statements.

FASB has issued an Exposure Draft on a Proposed Interpretation of SFAS Statement No. 143, "Accounting for Conditional Asset Retirement Obligations." SFAS 143 requires the recognition of a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The proposed interpretation is in response to diverse accounting practices that have developed with respect to the timing of liability recognition for conditional asset retirement obligations. If adopted, the interpretation may be applicable to BPA effective in fiscal year 2005.

2. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which BPA is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to the U.S. Treasury in the absence of the Refinancing Act, plus $100 million. The $100 million was capitalized as part of the appropriations balance and was included pro rata in the new principal of the individual appropriated repayment obligations. The amount of appropriations refinanced was $6.6 billion. After refinancing, the appropriations outstanding were $4.1 billion. The difference between the appropriated debt before and after the refinancing was recorded as a capitalization adjustment. This adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act. Amortization of the capitalization adjustment was $68.6 million, $67.7 million and $67.4 million for fiscal years 2004, 2003 and 2002 respectively.

Construction and replacement of Corps and Reclamation generating facilities historically have been financed through annual federal appropriations. Annual appropriations also were made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the Energy Policy Act of 1992 BPA directly funds operation and maintenance expenses and capital efficiency and reliability improvements for Corps and Reclamation generating facilities.

Federal generation and transmission appropriations are repaid to the U.S. Treasury within the weighted average service lives of the associated investments (maximum 50 years) from the time each facility is placed in service.

If, in any given year, revenues are not sufficient to cover all cash needs, including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This interest must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

The table shows the term repayments on the remaining federal appropriations as of Sept. 30, 2004.

Federal Appropriations

As of Sept. 30 — thousands of dollars

	Term Repayments
2005	$ 104,673
2006	68,939
2007	33,694
2008	10,913
2009	9,889
2010+	4,215,860
	$ 4,443,968

The weighted average interest rate was 7.0 percent on outstanding appropriations as of Sept. 30, 2004. Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

3. Long-Term Debt

To finance its capital programs, BPA is authorized by Congress to issue to the U.S. Treasury up to $4.45 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. Of the $4.45 billion, $1.25 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2004, of the total $2.9 billion of outstanding bonds, $780 million were conservation and renewable resource loans and grants (including Corps, Reclamation and U.S. Fish & Wildlife capital investments). The average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently. As a result, the fair value of BPA long-term debt, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2004, for similar maturities, exceeds carrying value by approximately $224 million, or 7.7 percent.

The table on the following page reflects the terms and amounts of long-term debt.

4. Nonfederal Projects

BPA has acquired all or part of the generating capability of five nuclear power plants. The contracts to acquire the generating capability of the projects, referred to as "net-billing agreements," require BPA to pay all or part of the annual projects' budgets, including operating expense and debt service, including projects that are not completed and/or not operating. BPA also has acquired all of the output of the Cowlitz Falls and Northern Wasco hydro projects. BPA has agreed to fund debt service on Emerald People's Utility District, City of Tacoma and Conservation and Renewable Energy System bonds issued to finance conservation programs sponsored by BPA.

BPA recognizes expenses for these projects based upon total project cash funding requirements.

Operating expense for the projects of $230 million, $223 million and $175 million in fiscal years 2004, 2003 and 2002 respectively, is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $247 million, $120 million, and $230 million for fiscal years 2004, 2003 and 2002 respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses. Refinancing activities reduced debt service by $333 million, $463 million and $319 million for fiscal years 2004, 2003 and 2002 respectively, from rate case estimates.

Bonds issued to U.S. Treasury

Long-Term Debt (1) — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Amount	Cumulative Total
January 2000	none	2005	7.15%	$ 53,500	$ 53,500
January 2001	none	2005	5.65%	20,000	73,500
January 2001	none	2005	5.65%	25,000	98,500
March 2002	none	2005	4.60%	110,000	208,500
March 2002	none	2005	4.60%	30,000	238,500
May 1997	none	2005	6.90%	80,000	318,500
June 2002	none	2005	3.75%	60,000	378,500
June 2002	none	2005	3.75%	40,000	418,500
September 2000	none	2005	6.70%	20,000	438,500
October 2002	none	2005	3.00%	50,000	488,500
November 2002	none	2005	2.80%	40,000	528,500
April 2003	none	2006	2.40%	40,000	568,500
April 2003	none	2006	2.40%	25,000	593,500
July 2003	none	2006	2.30%	75,000	668,500
July 2003	none	2006	2.30%	30,000	698,500
August 1996	none	2006	7.05%	70,000	768,500
September 2000	none	2006	6.75%	40,000	808,500
September 2002	none	2006	3.05%	100,000	908,500
September 2002	none	2006	3.05%	30,000	938,500
September 2002	none	2006	3.05%	20,000	958,500
September 2003	none	2006	2.50%	20,000	978,500
September 2003	none	2006	2.50%	25,000	1,003,500
December 2002	none	2006	3.05%	40,000	1,043,500
January 2004	none	2007	2.50%	60,000	1,103,500
January 2004	none	2007	2.50%	25,000	1,128,500
April 2003	none	2007	2.90%	40,000	1,168,500
April 2004	none	2007	2.95%	65,000	1,233,500
April 2004	none	2007	2.95%	35,000	1,268,500
July 2003	none	2007	2.95%	25,000	1,293,500
July 2004	none	2007	3.45%	50,000	1,343,500
July 2004	none	2007	3.45%	25,000	1,368,500
August 1997	none	2007	6.65%	111,300	1,479,800
September 2003	none	2007	3.10%	20,000	1,499,800
September 2004	none	2007	3.10%	30,000	1,529,800
September 2004	none	2007	3.10%	30,000	1,559,800
January 2004	none	2008	2.95%	65,000	1,624,800
January 2004	none	2008	2.95%	30,000	1,654,800
April 1998	none	2008	6.00%	75,300	1,730,100
April 1998	none	2008	6.00%	25,000	1,755,100
July 2004	none	2008	3.80%	25,000	1,780,100
August 1998	none	2008	5.75%	40,000	1,820,100
September 1998	none	2008	5.30%	104,300	1,924,400
May 1998	none	2009	6.00%	72,700	1,997,100
May 1998	none	2009	6.00%	37,700	2,034,800
July 1989	none	2009	8.55%	40,000	2,074,800
January 2001	none	2010	6.05%	60,000	2,134,800
January 2001	none	2010	6.05%	30,000	2,164,800
May 1998	none	2011	6.20%	40,000	2,204,800
June 2001	none	2011	5.95%	25,000	2,229,800
August 2001	none	2011	5.75%	50,000	2,279,800
January 1998	none	2013	6.10%	60,000	2,339,800
September 1998	none	2013	5.60%	52,800	2,392,600
February 1999	none	2014	5.90%	60,000	2,452,600
April 1998	2008	2028	6.65%	50,000	2,502,600
August 1998	none	2028	5.85%	106,500	2,609,100
August 1998	none	2028	5.85%	112,300	2,721,400
May 1998	2008	2032	6.70%	98,900	2,820,300
April 2003	2008	2033	5.55%	40,000	2,860,300
September 2004	none	2034	5.60%	40,000	2,900,300
				$ 2,900,300	$ 2,900,300
Less current portion					(438,500)
					$ 2,461,800

(1) The weighted average interest rate was 4.9 percent on outstanding long-term debt as of Sept. 30, 2004. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

The fair value of all Energy Northwest debt exceeds recorded value by $454 million, or 7.5 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2004. All other nonfederal projects' debt approximates fair value as stated.

Construction of the Schultz-Wautoma transmission line was financed through Northwest Infrastructure Financing Corporation (NIFC), a Delaware "Special Purpose Corporation," formed on Dec. 17, 2003. In March 2004, NIFC issued $119.6 million in taxable bonds to finance the line under a lease-purchase agreement. NIFC owns the line and BPA leases the line for 30 years. Lease revenues from BPA back the bonds. BPA is managing construction and will operate the line. BPA has indemnified the equity owners of NIFC for all construction and operating risks associated with the line. BPA will have exclusive use and control of the asset during the lease period. At the end of the lease, BPA has the option to buy the line at a bargain purchase price. BPA has determined it is the primary beneficiary of NIFC. As such, NIFC financial statements are consolidated into BPA financial statements in accordance with FIN 46. Therefore the bonds are included as nonfederal debt on FCRPS's financial statements. NIFC's assets are included in FCRPS other assets at Sept. 30, 2004.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2004.

Nonfederal Projects Debt (1)

As of Sept. 30 — thousands of dollars

	Principal Repayments
2005	$ 234,896
2006	253,632
2007	296,435
2008	304,593
2009	310,789
2010+	5,053,483
	$ 6,453,828

(1) The weighted average interest rate was 5.6 percent on the major portion of outstanding nonfederal projects debt as of Sept. 30, 2004.

5. Investor-owned Utility Exchange Benefits

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), beginning in 1982 BPA entered into residential exchange contracts with most of its electric utility customers. These contracts resulted in payments to the utilities if a utility's average system cost exceeded BPA's priority firm power rate on the "exchanged" power. These payments were required to be passed through to their qualified residential and small-farm customers.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except Northwestern Energy (formerly the Montana Power Co.), which had not been receiving benefits. BPA made payments to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011.

In October 2000, BPA's investor-owned utility (IOU) customers signed Subscription settlement agreements, under which BPA was to provide monetary and power benefits in place of residential exchange benefits for the period July 1, 2001, through Sept. 30, 2011. These agreements provide for both sales of power and monetary benefit payments to the IOUs and also allow the power to be converted to cash payments.

Amendments to the October 2000 contracts allowed payment of a portion of the fiscal year 2003 IOU Subscription settlement benefits to be deferred and paid in the fiscal year 2007 through 2011 period, except when they were reduced through credits to offset the SN CRAC.

IOU Exchange Benefit amounts for fiscal years 2005 and 2006 could range from $382 million to $750 million for the two years combined depending on the level of SN CRAC in fiscal year 2006. These estimates include $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. As the SN CRAC percentage has been set at zero percent for fiscal year 2005, an estimate for fiscal year 2005 IOU Exchange Benefits has been recorded as a current liability on the Balance Sheet.

In May 2004, BPA signed new contracts and amendments with all six IOU customers entitled "Agreements Regarding Payment of Residential Exchange Program Settlement Benefits During Fiscal Years 2007-2011." These latest agreements established a method for calculating the IOUs' Monetary Benefits for the fiscal years 2007 through 2011 period including an annual floor of $100 million and an annual cap of $300 million for the six IOUs in total, and all parties agreed that BPA would have no obligation to provide power to the IOUs during that period. The new agreements also eliminated $100 million of a $200 million risk contingency payment owed to two IOUs that have load reduction payments, and deferred the remaining $100 million payment and related interest to the fiscal years 2007 through 2011 period.

IOU Exchange Benefit amounts for the fiscal year 2007 through 2011 period cannot yet be calculated, however the annual floor of $100 million has been recorded as a liability on the Balance Sheets (for total floor of $500 million for this time period). In addition, the IOU Risk Contingency Payment amounts that were deferred in fiscal year 2004 will be repaid $20 million per year (plus interest) during the fiscal year 2007 through 2011 period and have been recorded as a liability on the Balance Sheets.

Financial benefits beyond fiscal year 2011 cannot currently be quantified.

6. Accrued Plant Removal Costs

Pursuant to regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2004 and 2003, BPA has estimated $105 million and $147 million regulatory liabilities respectively, for removal costs and has reclassified these amounts from accumulated depreciation to a regulatory liability.

7. Commitments and Contingencies

Purchase and Sales Commitments

BPA has entered into Subscription power sales for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. These contracts run for as short as three years and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through fiscal year 2006. BPA's trading floor enters into sales commitments to sell expected surplus generating capabilities at future dates and purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into these contracts throughout the year to maximize its revenues on estimated surplus volumes. BPA records these sales and purchases in the month the underlying power is delivered.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2004.

Purchase Power and Sales Commitments*

As of Sept. 30 — thousands of dollars

	Purchase	Sales
2005	$ 629,994	$ 2,279,339
2006	571,990	2,117,166
2007	92,202	1,553,848
2008	48,561	1,563,224
2009	48,878	1,562,069
2010+	98,815	3,139,667
	$1,490,440	**$12,215,313**

*Augmentation commitments run through 2006. Purchases and sales have not been reduced for bookouts.

Irrigation Assistance

As directed by legislation, BPA is required to make cash distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects that have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation and are required only if doing so does not result in an increase to power rates. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues (expenses) when paid. BPA paid irrigation assistance payments of $739 thousand, $17 million, and $25 million for fiscal years 2004, 2001 and 1997 respectively. Future irrigation assistance payments ultimately could total $667 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2004.

Irrigation Assistance

As of Sept. 30 — thousands of dollars

	Distributions
2005	$ —
2006	—
2007	—
2008	2,950
2009	6,590
2010+	657,693
	$ 667,233

On Aug. 2, 2004, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2003) from the Bureau of Reclamation. The numbers above, reflect that new schedule. They exclude $56.6 million assistance for Lower Teton, which was never completed, therefore never produced electricity and the administrator has no obligation to recover these costs.

Additional Pension and Other Post-Retirement Plan Contributions Retirement Benefits

FCRPS makes additional annual contributions to the U.S. Treasury in order to ensure that all federal post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed. The additional contributions are based on employee plan participation and the extent to which the particular plans are under funded. BPA paid $30.9 million, $35.1 million and $55.2 million to the U.S. Treasury during fiscal years 2004, 2003 and 2002, respectively. These amounts were recorded as expense when paid. At Sept. 30, 2004, FCRPS has scheduled additional payments totaling $119.6 million as shown in the following table.

Additional Pension and Other Post-Retirement Plan Contributions

As of Sept. 30—thousands of dollars

	Scheduled Contributions
2005	$ 26,500
2006	23,200
2007	21,100
2008	18,000
2009	30,750*
	$ 119,550

FCRPS expects to recognize these amounts as expense in the years in which they are specifically recovered through rates.

* 2009 is an estimate not currently scheduled.

Net-Billing Agreements

BPA has agreed with Energy Northwest that in the event any participant shall be unable for any reason, or shall refuse, to pay to Energy Northwest any amount due from such participant under its net-billing agreement for which a net-billing credit or cash payment to such participant has been provided by BPA, BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the net-billing agreements.

Decommissioning and Restoration Costs

In 1999 Energy Northwest transferred remaining WNP-3 and WNP-5 assets, including the real property, and site restoration liability to a consortium of local governments named the Satsop Redevelopment Project. BPA's site restoration obligations related to WNP-3 and WNP-5 were satisfied/liquidated as part of that transfer.

In December 2003, the state of Washington's Energy Facility Site Evaluation Council (EFSEC) approved Resolution No. 302, approving Energy Northwest's revised Dec. 5, 2002 Site Restoration Plan for WNP-1 and WNP-4. This approval was part of a contemporaneous comprehensive agreement between Energy Northwest, EFSEC, BPA and the U.S. Department of Energy – Richland Operations Office (lessor of the real property upon which the partially completed WNP-1 and WNP-4 are located). Under the terms of the comprehensive agreement, the level of site restoration agreed to involves partial demolition and sealing of project structures (Level 3D – without removal of the turbine pedestals). BPA committed to fund that level of site restoration for both projects in two phases. The estimated total site restoration costs for both sites is $31 million (2003 dollars).

Phase 1 will involve completion of near term restoration (within 18 to 24 months of Dec. 15, 2003) involving essential "Health, Safety and Environmental" protection designed to place the sites in a safe state for potential reuse and/or long-term storage. Absent long-term reuse, Phase 2 will commence in 23 years and will complete all remaining activities to implement Level 3D restoration.

In order to fund the Phase 2 site restoration obligations, BPA has placed $18 million in an external Trust Fund. BPA believes those funds plus projected earnings over the 23-year horizon will be adequate to cover most if not all costs for Phase 2 activities. Phase 2 site restoration will take place absent long-term reuse of the site and structures. BPA's obligation is not, however, conditioned upon the posited earnings growth of the initial amounts deposited in the Trust Fund or upon the posited total cost estimate. A reasonable extension of time could be provided if such additional funds for completion of Phase 2 site restoration are ultimately required due to higher than estimated costs to complete the work.

Decommissioning costs for Columbia Generating Station (CGS) are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for CGS. The sinking fund is expected to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this deferred decontamination period be no longer than 60 years. Sinking fund requirements for CGS are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning and site restoration expenditures for CGS are $673 million (2003 dollars). BPA has recorded an estimated liability of $91.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking funds for fiscal years 2004, 2003 and 2002 were approximately $5 million, $4.8 million and $4.5 million respectively. The sinking fund balances at Sept. 30, 2004, are $85 million and $9.7 million for decommissioning and site restoration respectively.

In January 1993, the Portland General Electric (PGE) board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $265 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2004, Eugene Water and Electric Board's (EWEB) 30-percent share, which BPA backs, of this estimated remaining liability is $46 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143). The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements have been greater in the early years of decommissioning and will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for fiscal years 2001, 2002 and 2003. For fiscal years 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In fiscal years 2002 and 2003, the decommissioning trust fund was used to fund a portion of the fiscal years 2002 and 2003 Trojan decommissioning expenses. In fiscal year 2004, BPA again directly funded Trojan decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover EWEB's 30 percent share of Trojan's costs through rates. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses. These costs incorporate the impacts of SFAS 143.

Nuclear Insurance

BPA is a member of the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company established to provide insurance coverage for nuclear power plants. The types of insurance coverage purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decommissioning Liability and Excess Property Insurance; and 3) Business Interruption and/or Extra Expense Insurance.

Under each insurance policy BPA could be subject to an assessment in the event that a member-insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Insurance policy is $6.8 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $14.1 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.5 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $300 million, BPA could be subject to a retrospective assessment of $95.8 million limited to an annual maximum of $10 million. Assessments would be included in BPA's costs and recovered through current rates.

Endangered Species Act

Actions related to the Endangered Species Act are included in BPA's costs and recovered through current rates.

Environmental Cleanup

From time to time, there are sites where BPA, Corps or Reclamation have been or may be identified as a potential responsible party. Costs associated with cleanup of those sites are not expected to be material to the FCRPS financial statements and would be recoverable through future rates.

8. Litigation

The FCRPS is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the FCRPS is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the FCRPS's financial position or results of operations.

Judgments and settlements are included in BPA's costs and recovered through current rates.

9. Segments

In fiscal year 1997 BPA opted to implement FERC's open-access rulemaking and standards of conduct. FERC requires that transmission activities are functionally separate from wholesale power merchant functions and that transmission is provided in a nondiscriminatory open-access manner.

The FCRPS's major operating segments are defined by the utility functions of generation and transmission. The Power Business Line represents the operations of the generation function, while the Transmission Business Line represents the operations of the transmission function. The business lines are not separate legal entities. Where applicable, "Corporate" represents items that are necessary to reconcile to the financial statements, which generally include shared activity and eliminations. Each FCRPS segment operates predominantly in one industry and geographic region: the generation and transmission of electric power in the Pacific Northwest.

The FCRPS centrally manages all interest expense activity. Since BPA has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed. Unaffiliated revenues represent sales to external customers for each segment. Inter-segment revenues are eliminated.

Major Customers

During fiscal years 2004, 2003 and 2002, no single customer represented 10 percent or more of the FCRPS' revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Corporate	Consolidating	FCRPS
2004					
Unaffiliated revenues	$ 2,661,975	$ 535,936	$ —	$ —	$ 3,197,911
Intersegment revenues	76,923	108,123	—	(185,046)	—
Total operating revenues	2,738,898	644,059	—	(185,046)	3,197,911
Unaffiliated expenses	1,971,620	252,738	(181,952)	—	2,042,406
Depreciation	177,297	188,942	—	—	366,239
Intersegment expenses	108,194	76,758	94	(185,046)	—
Total operating expenses	2,257,111	518,438	(181,858)	(185,046)	2,408,645
Interest expense	162,531	137,823	(15,503)	—	284,851
Net revenues (expenses)	$ 319,256	$ (12,202)	$ 197,361	$ —	$ 504,415
2003					
Unaffiliated revenues	$ 3,059,386	$ 552,718	$ —	$ —	$ 3,612,104
Intersegment revenues	85,425	110,884	—	(196,309)	—
Total operating revenues	3,144,811	663,602	—	(196,309)	3,612,104
Unaffiliated expenses	2,435,923	240,460	(315,320)	—	2,361,063
Depreciation	178,896	171,130	—	—	350,026
Intersegment expenses	110,401	85,788	120	(196,309)	—
Total operating expenses	2,725,220	497,378	(315,200)	(196,309)	2,711,089
Interest expense	176,595	168,996	—	—	345,591
Net revenues (expenses)	$ 242,996	$ (2,772)	$ 315,200	$ —	$ 555,424

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2004 — thousands of dollars

Schedule A

		Commercial Power			Irrigation *(unaudited)*		
	Total Plant	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation
Bonneville Power Administration							
Transmission Facilities	$ 6,030,980	$ 5,539,134	$ 491,846	$ 6,030,980	$ —	$ —	$ —
Bureau of Reclamation							
Boise	144,493	27,577	404	27,981	(2,731)	67,539	64,808
Columbia Basin	1,964,353	1,238,515	60,682	1,299,197	495,526	142,008	637,534
Green Springs	35,726	11,175	212	11,387	9,934	8,070	18,004
Hungry Horse	149,212	121,985	285	122,270	—	—	—
Minidoka-Palisades	383,665	112,088	(37)	112,051	386	72,472	72,858
Yakima	264,243	6,127	725	6,852	13,762	127,826	141,588
Total Bureau Projects	2,941,692	1,517,467	62,271	1,579,738	516,877	417,915	934,792
Corps of Engineers							
Albeni Falls	50,605	43,126	2,809	45,935	—	—	—
Bonneville	1,401,586	927,603	69,656	997,259	—	—	—
Chief Joseph	629,987	571,149	18,368	589,517	—	163	163
Cougar	118,861	36,314	40,354	76,668	—	3,288	3,288
Detroit-Big Cliff	74,095	41,220	6,748	47,968	—	5,050	5,050
Dworshak	376,722	316,782	2,464	319,246	—	—	—
Green Peter-Foster	95,965	50,955	4,680	55,635	—	6,222	6,222
Hills Creek	51,457	18,463	1,265	19,728	—	4,623	4,623
Ice Harbor	223,909	159,247	3,937	163,184	—	—	—
John Day	657,206	494,244	14,816	509,060	—	—	—
Libby	577,223	433,212	1,240	434,452	—	—	—
Little Goose	255,468	212,068	1,738	213,806	—	—	—
Lookout Point-Dexter	113,180	50,192	10,787	60,979	—	1,496	1,496
William Jess (Lost Creek)	149,836	26,972	174	27,146	—	2,184	2,184
Lower Granite	414,613	332,599	8,459	341,058	—	—	—
Lower Monumental	276,546	230,564	3,071	233,635	—	—	—
McNary	397,747	300,736	21,626	322,362	—	—	—
The Dalles	424,917	308,486	66,985	375,471	—	—	—
Lower Snake	262,143	256,193	3,380	259,573	—	—	—
Columbia River Fish Bypass	920,589	376,958	529,058	906,016	—	—	—
Total Corps Projects	7,472,655	5,187,083	811,615	5,998,698	—	23,026	23,026
AFUDC on Direct Funded Projects	36,062	—	36,062	36,062	—	—	—
Irrigation Assistance at 12 Projects having no power generation	193,925	—	—	—	148,553	45,372	193,925
Total Plant Investment	16,675,314	12,243,684	1,401,794	13,645,478	665,430	486,313	1,151,743
Repayment obligation retained by Columbia Basin project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton project (2)	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$16,759,060	$12,246,520	$1,409,063	$13,655,583	$723,806	$489,994	$1,213,800

(1) Amount represents joint costs transferred to Bureau of Sports Fisheries and Wildlife. This is included in other assets in the accompanying balance sheets.

(2) The $7,269,000 commercial power portion of the Teton project is included in other assets in the accompanying balance sheets. Teton amounts exclude interest totaling approximately $2.2 million subsequent to June 1976, which was charged to expense.

	Non-reimbursable *(unaudited)*					
	Navigation	Control	Flood Wildlife	Fish and Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	51,704	17.47%
Columbia Basin	—	17,489	6,054	3,071	1,008	91.36%
Green Springs	—	—	—	—	6,335	59.68%
Hungry Horse	—	26,942	—	—	—	81.94%
Minidoka-Palisades	—	64,404	2,718	10,651	120,983	29.31%
Yakima	—	2,547	50,397	296	62,563	7.80%
Total Bureau Projects	—	111,382	59,169	14,018	242,593	71.27%
Corps of Engineers						
Albeni Falls	183	274	—	4,213	—	90.77%
Bonneville	400,999	—	—	1,266	2,062	71.15%
Chief Joseph	—	—	4,977	6,330	29,000	93.58%
Cougar	548	38,357	—	—	—	64.50%
Detroit-Big Cliff	220	20,857	—	—	—	64.74%
Dworshak	9,733	31,934	—	15,809	—	84.74%
Green Peter-Foster	366	30,379	—	1,693	1,670	57.97%
Hills Creek	630	26,476	—	—	—	38.34%
Ice Harbor	57,184	—	—	3,541	—	72.88%
John Day	91,535	18,240	—	11,962	26,409	77.46%
Libby	—	95,308	876	15,950	30,637	75.27%
Little Goose	34,917	—	—	4,141	2,604	83.69%
Lookout Point-Dexter	748	49,355	—	602	—	53.88%
Lost Creek	—	52,967	24,483	29,435	13,621	18.12%
Lower Granite	52,605	—	—	13,108	7,842	82.26%
Lower Monumental	39,596	—	—	2,898	417	84.48%
McNary	70,413	—	—	4,972	—	81.05%
The Dalles	47,346	—	—	2,078	22	88.36%
Lower Snake	2,570	—	—	—	—	99.02%
Columbia River Fish Bypass	11,792	2,781	—	—	—	98.42%
Total Corps Projects	821,385	366,928	30,336	117,998	114,284	80.28%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	76.60%
Total Plant Investment	821,385	478,310	89,505	132,016	356,877	85.82%
Repayment obligation retained by Columbia Basin project	—	—	—	—	—	100.00%
Investment in Teton project	—	9,151	—	2,433	—	80.70%
	$ 821,385	$ 487,461	$ 89,505	$134,449	$356,877	85.80%

Schedule of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

Schedule B

	2004	2003	2002
Operating Revenues			
Sales of electric power:			
Sales within the Northwest Region			
Northwest Publicly Owned Utility Customers [1]	$ 1,737,895	$ 1,723,341	$ 1,798,477
Direct Service Industrial Customers	92,424	18,494	58,466
Northwest Investor-Owned Utilities	363,201	436,702	378,083
Sales Outside the Northwest Region [2]	489,063	628,243	638,267
Bookouts [3]	(212,155)	—	—
Total Sales of Electric Power	2,470,428	2,806,780	2,873,293
Transmission	535,936	552,718	566,654
Fish Credits and Other Revenues [4]	191,547	252,606	93,782
Total Operating Revenues	3,197,911	3,612,104	3,533,729
Operating Expenses			
BPA O&M [5]	613,121	607,616	775,077
Purchased Power [3]	582,129	1,043,009	1,286,867
Corps, Bureau and Fish & Wildlife O&M [6]	214,035	198,539	198,055
Nonfederal entities O&M – net billed [7]	221,210	208,535	167,026
Nonfederal entities O&M – non-net billed [8]	37,521	39,864	35,566
Total Operation and Maintenance	1,668,016	2,097,563	2,462,591
Net billed debt service	222,779	104,329	213,919
Non-net billed debt service	25,696	15,205	16,256
Nonfederal Projects Debt Service [9]	248,475	119,534	230,175
Federal Projects Depreciation	366,239	350,025	335,205
Residential Exchange	125,915	143,967	143,983
Total Operating Expenses	2,408,645	2,711,089	3,171,954
Net Operating Revenues	789,266	901,015	361,775
Interest Expense			
Appropriated Funds	281,607	280,094	325,551
Long-term debt	110,251	166,598	151,997
Capitalization Adjustment [10]	(68,566)	(67,703)	(67,356)
Allowance for funds used during construction	(38,441)	(33,398)	(57,892)
Net Interest Expense	284,851	345,591	352,300
Net Revenues	$ 504,415	$ 555,424	$ 9,475

(1) This customer group includes municipalities, public utility districts and rural electric cooperatives in the region.

(2) In general, revenues from sales outside the Northwest are highly dependent upon streamflows in the Columbia River Basin. Streamflows directly impact the amount of nonfirm energy available for sale, the costs of generating power with alternative fuels, and ultimately the price BPA can obtain for its exported nonfirm energy and surplus firm power.

(3) Total operating expenses and revenue from electricity sales reflect recent accounting guidance from the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board. Under this new guidance (EITF 03-11) both revenues and expenses associated with non-trading energy activities that are “booked out” (settled other than by the physical delivery of power) are to be reported on a “net” basis in both operating revenues and purchased power expense. Formerly, such bookouts were to be treated on a “gross” basis. Application of the new guidance thus decreased both operating revenues and purchase power expense by $212 million and has no effect on the net revenue, cash flows or margins.

(4) These revenues relate primarily to fish and wildlife credits BPA receives for its U.S. Treasury repayment obligation. Mark-to-market adjustments and other miscellaneous revenues are also included.

(5) BPA operations and maintenance expenses include the costs of BPA’s transmission system, operation and maintenance program, energy resources, power marketing, and fish and wildlife programs.

(6) Corps, Reclamation and Fish & Wildlife operations and maintenance expenses include the costs of the Corps and Reclamation generating projects and expenses of the U.S. Fish & Wildlife Service, in connection with the federal system.

(7) The nonfederal entities O&M – net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which BPA has agreed to purchase under certain capitalized contracts, the costs of which are net billed.

(8) The nonfederal entities O&M – non-net billed expense includes the operation and maintenance costs for generating facilities and the generating capability or output of which BPA has agreed to purchase under certain capitalized contracts, the costs of which are not net billed.

(9) These amounts include payment by BPA for all or a part of the generating capability of, and debt service on, four nuclear power generating projects (three of which are terminated). They are Energy Northwest’s Project 1, Project 3, and Columbia Generating Station, and the City of Eugene Water and Electric Board’s 30 percent ownership share of the Trojan nuclear project. These amounts also include payment by BPA with respect to several small generating and conservation projects.

(10) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing federal appropriations under legislation enacted in 1996.

Report of Independent Auditors

PRICEWATERHOUSECOOPERS

To the Administrator of the
Bonneville Power Administration,
United States Department of Energy

In our opinion, the accompanying combined balance sheets and the related combined statements of changes in capitalization and long-term liabilities, of revenues and expenses and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2004 and 2003, and the results of its operations and its cash flows for the three years in the period ended September 30, 2004, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2004, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 of the financial statements, FCRPS changed the manner in which it accounts for realized gains and losses on the settled derivative contracts not held for trading purposes, as of October 1, 2003.

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The Schedule of Amount and Allocation of Plant Investment as of September 30, 2004 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2004 (Schedule B) are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
October 28, 2004