NEW ISSUE — BOOK ENTRY ONLY

In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville ("Special Tax Counsel"), based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2005 Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986 and Section 103 of the Internal Revenue Code of 1986 (the "Code") and is exempt from State of Oregon and Multnomah County, Oregon personal income taxes. In the further opinion of Special Tax Counsel, interest on the Series 2005 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings when calculating corporate alternative minimum taxable income. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2005 Bonds. See "TAX MATTERS."

$26,640,000
CITY OF EUGENE, OREGON

TROJAN PROJECT REVENUE BONDS
Refunding Series 2005

Dated: Date of Delivery **Due:** September 1, as shown on the inside cover

The City of Eugene, Oregon (the "City") acting by and through the Eugene Water & Electric Board (the "Board") is issuing its $26,640,000 Trojan Project Revenue Bonds, Refunding Series 2005 (the "Series 2005 Bonds") for the purpose of refunding all of the City's outstanding Trojan Project Revenue Bonds, Series of 1977, and to pay costs relating to the issuance of the Series 2005 Bonds, as more fully described herein. Wells Fargo Bank, National Association, will serve as Bond Fund Trustee with respect to the Series 2005 Bonds.

The Series 2005 Bonds will be issued in fully registered form, registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Series 2005 Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the registered owner of the Series 2005 Bonds and nominee of DTC, references herein to holders or registered owners shall mean Cede & Co. and shall not mean the beneficial owners of the Series 2005 Bonds. See "BOOK-ENTRY ONLY SYSTEM". Interest on the Series 2005 Bonds is payable semiannually on September 1 and March 1 of each year, commencing September 1, 2005. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2005 Bonds will be made to such registered owner, and disbursement of such payments will be the responsibility of DTC and DTC participants as described herein.

The Series 2005 Bonds are not subject to redemption prior to maturity.

The Series 2005 Bonds are special revenue obligations of the City, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The Series 2005 Bonds are not a general obligation of the State of Oregon or of any political subdivision thereof. Neither the full faith and credit nor the taxing power of the City is pledged to the payment of the Series 2005 Bonds. See "SECURITY FOR THE SERIES 2005 BONDS."

MATURITY SCHEDULE —See Inside Cover

The Series 2005 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Hawkins Delafield & Wood LLP, New York, New York, Bond Counsel to the Board, and to certain other conditions. Certain legal matters will be passed upon for the Board by Cable Huston Benedict Haagensen & Lloyd LLP and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters will be passed upon for the Underwriters by Foster Pepper & Shefelman PLLC, Spokane, Washington, Counsel to the Underwriters. It is expected that the Series 2005 Bonds in definitive form will be available to DTC in New York, New York, on or about April 19, 2005.

JPMorgan **Goldman, Sachs & Co.**

April 7, 2005

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES AND YIELDS

$26,640,000 Trojan Project Revenue Bonds
Refunding Series 2005

Year (September 1)	Amount	Interest Rate	Yield	CUSIP
2005	$3,205,000	3.00%	2.40%	298239 AA2
2006	7,435,000	5.00	2.70	298239 AB0
2007	7,805,000	5.00	2.95	298239 AC8
2008	8,195,000	5.00	3.10	298239 AD6

EUGENE WATER & ELECTRIC BOARD
500 East 4th Avenue
Eugene, Oregon 97440-2148

Board of Commissioners

Ron Farmer, President	John Simpson, Commissioner
Sandra Bishop, Vice President	Melvin Menegat, Commissioner
Patrick Lanning, Commissioner	

Executive Management

General Manager	Randy L. Berggren
Director, Water and Steam	Thomas E. Buckhouse
Director, Corporate Services	Roseanna McArthur
Director, Customer and Financial Services	James H. Origliosso
Director, Power Resources	Richard C. Helgeson
Director, Electric Division	James P. Wiley

Corporate Officers to the Board

Secretary	Randy L. Berggren
Assistant Secretary	Krista K. Hince
Treasurer	James H. Origliosso
Assistant Treasurer	Catherine D. Bloom

Financial Advisor
Seattle Northwest Securities Corporation

Bond Counsel to the Board
Hawkins Delafield & Wood LLP

Special Counsel
Cable Huston Benedict Haagensen & Lloyd

PricewaterhouseCoopers LLP
Independent Auditor

General Counsel
Calkins & Calkins

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
Portland, Oregon 97208
Telephone (403) 230-3000

Administrator and Chief Executive Officer	Stephen J. Wright
Deputy Administrator and Deputy Chief Executive Officer	Steven G. Hickok
Chief Operating Officer	Ruth B. Bennett
General Counsel	Randy A. Roach
Chief Financial Officer (Acting)	Nancy M. Mitman

Special Counsel to Bonneville
Orrick, Herrington & Sutcliffe LLP

Financial Advisor to Bonneville
Public Financial Management

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NO DEALER, BROKER, SALESMAN OR OTHER PERSON IS AUTHORIZED BY THE BOARD, THE CITY, BONNEVILLE OR THE UNDERWRITERS TO GIVE ANY INFORMATION OR TO MAKE ANY REPRESENTATIONS OTHER THAN THOSE CONTAINED IN THIS OFFICIAL STATEMENT IN CONNECTION WITH THE OFFERING OF THE SERIES 2005 BONDS, AND, IF GIVEN OR MADE, SUCH INFORMATION OR REPRESENTATIONS MUST NOT BE RELIED UPON AS HAVING BEEN AUTHORIZED BY THE BOARD, THE CITY, BONNEVILLE OR THE UNDERWRITERS. THIS OFFICIAL STATEMENT DOES NOT CONSTITUTE AN OFFER TO SELL OR A SOLICITATION OF AN OFFER TO BUY THE SERIES 2005 BONDS, NOR SHALL THERE BE ANY SALE OF THE SERIES 2005 BONDS BY ANY PERSON IN ANY STATE IN WHICH IT IS UNLAWFUL TO MAKE SUCH OFFER, SALE OR SOLICITATION, AND NO DEALER, BROKER, SALESMAN OR OTHER PERSON HAS BEEN AUTHORIZED OR IS AUTHORIZED BY THE BOARD, THE CITY OR THE UNDERWRITERS TO MAKE SUCH OFFER, SALE OR SOLICITATION.

The information set forth herein has been furnished by the Board, the City and Bonneville and includes information obtained from other sources which are believed to be reliable, the information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Board, the City or Bonneville since the date hereof.

This Official Statement contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words, "estimate," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. A number of important factors affecting the Board's, the City's or Bonneville's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements.

The Underwriters have provided the following sentence for inclusion in the Official Statement: "The Underwriters have reviewed the information in the Official Statement in accordance with, and as a part of, their respective responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information."

IN CONNECTION WITH THE OFFERING OF THE SERIES 2005 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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$26,640,000

CITY OF EUGENE, OREGON

Trojan Project Revenue Bonds Refunding Series 2005

This Official Statement of the City of Eugene, Oregon (the "City"), acting by and through the Eugene Water & Electric Board (the "Board"), which includes the cover page and the appendices hereto, sets forth information concerning the City, the Board, the Bonneville Power Administration ("Bonneville"), the Trojan Nuclear Plant (the "Project" or the "Trojan Project") and the City's $26,640,000 Trojan Project Revenue Bonds, Refunding Series 2005 (the "Series 2005 Bonds"). The Series 2005 Bonds are to be issued pursuant to the Charter of the City, the Oregon Revised Statutes, a Resolution authorizing the issuance of Trojan Project Revenue Bonds (the "Bonds") and a First Supplemental Resolution authorizing the Series 2005 Bonds, each adopted by the Board on September 21, 2004 (such resolutions being collectively referred to as the "Resolution"). Wells Fargo Bank, National Association, will serve as Bond Fund Trustee with respect to the Series 2005 Bonds.

Definitions of certain capitalized terms used in this official statement are defined in Appendix G—"DEFINITIONS OF CERTAIN TERMS USED IN THIS OFFICIAL STATEMENT".

INTRODUCTION

The City and the Board

The City is a charter city operating under a charter most recently revised in 2002. The Board is an administrative unit of the City and is responsible for the operation of the City's water and electric utilities. For a general description of the City and the Board see "THE CITY OF EUGENE AND THE EUGENE WATER & ELECTRIC BOARD" herein. For a description of the Electric System operated by the Board on behalf of the City, see Appendix C — "EUGENE WATER & ELECTRIC BOARD AND ITS ELECTRIC SYSTEM". For a description of the Board's financial policies and controls, risk management policies, capital asset and long-term debt activity and related topics, see Appendix D — "FINANCIAL STATEMENTS OF THE EUGENE WATER & ELECTRIC BOARD."

Use of Series 2005 Bond Proceeds; The Project

The Series 2005 Bonds are being issued to refund and redeem all of the City's outstanding Trojan Nuclear Project Revenue Bonds, Series of 1977 (the "Series 1977 Bonds"), at the redemption price of par plus accrued interest and to pay certain costs of issuing the Series 2005 Bonds. The Series 1977 Bonds are outstanding in the principal amount of $44,600,000 and will be redeemed within 45 days after the issuance of the Series 2005 Bonds. The Series 1977 Bonds were issued to finance, in part, the City's ownership share of the Trojan Project, which ownership interest (the "Ownership Share") is described below. The Project, which operated from 1976 until it was terminated in 1992, is being decommissioned pursuant to a decommissioning plan (the "Trojan Decommissioning Plan") approved by the Nuclear Regulatory Commission ("NRC") in 1996. See "THE PROJECT" and "LITIGATION - Spent Fuel Litigation" herein for more information regarding the decommissioning of the Project.

Security for the Series 2005 Bonds

The Series 2005 Bonds are being issued as "Bonds" under the Resolution, and, as such, the Series 2005 Bonds are payable as to principal and interest solely from and are equally and ratably secured solely by a lien on and pledge of the Revenues, subject to the payment of Project Expenses, in accordance with their terms and the provisions of the Resolution, and amounts on deposit in the Trojan General Fund held by the Board. "Revenues" include all revenues derived by the City or Board from its Ownership Share of the Trojan Project, including all payments to the Board pursuant to the Net Billing Agreements (hereafter defined) and all payments to be made by the Board pursuant to the provision described under the caption Appendix H — "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — Covenants — Transfer in the Amounts of Credits Received Under the Two-Party Net Billing Agreement" and all interest and other investment earnings on any moneys or investments held in any funds and accounts under the Resolution. For the definition of "Revenues" and "Project Expenses" see "SECURITY FOR THE SERIES 2005 BONDS — General" and Appendix G — "DEFINITIONS OF CERTAIN TERMS USED IN THIS OFFICIAL STATEMENT".

The United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") has acquired the City's Ownership Share of the capability of the Project. The City assigned a portion (48.333%) of its Ownership Share of Project capability to Bonneville pursuant to a Two-Party Net Billing Agreement (the "Two-Party Net Billing Agreement") between Bonneville and the City and sold the remaining portion (51.667%) of its Ownership Share of Project capability to 13 electric utilities in Oregon and Washington (each, a "Participant"), which in turn assigned such Project capability to Bonneville pursuant to 13 separate Three-Party Net Billing Agreements (the "Three-Party Billing Agreements") among Bonneville, each Participant and the City. (The Two-Party Billing Agreement and the Three-Party Net Billing Agreements are collectively referred to herein as the "Net Billing Agreements"). The Net Billing Agreements have been terminated but certain provisions thereof continue in effect, including the payment provisions. See "THE NET BILLING AGREEMENTS."

Under the Two-Party Net Billing Agreement Bonneville is obligated to pay to the City its Participant's Share of the costs of the Trojan Project by crediting (or net billing) Bonneville's bills to the Board for power and certain other services purchased by the Board from Bonneville, and, under certain circumstances, by utilizing the assignment procedures of the Net Billing Agreements described below or making cash payments (which cash payments would be payable from the Bonneville Fund, as described herein). Under the Resolution, the Board is required to transfer from the Electric System Revenues to the Trojan General Fund an amount equal to the net billing credits so received. Any cash payments received from Bonneville are to be deposited directly to the Trojan General Fund. See "THE NET BILLING AGREEMENTS — Assignment of Shares; Cash Payments." The Board's ability to make the transfers from its Electric System Revenue Fund to the Trojan General Fund is dependent on the availability of Electric System Revenues. See "SECURITY FOR THE SERIES 2005 BONDS — Bond Resolution Rate Covenant" and "CERTAIN INVESTMENT CONSIDERATIONS AND RISK FACTORS —Risk of Events Pertaining to the Board".

Under the Three-Party Net Billing Agreements, the Participants are obligated to make payments to the Board in accordance with each Participant's participation in the purchase of the City's Ownership Share of the capability of the Project. Bonneville in turn is obligated to pay to each Participant its respective Participants' Share of the costs of the Trojan Project, in each case, by crediting (or net billing) Bonneville's bills to the Participant for power and certain other services purchased from Bonneville by the amount of the payment required to be made by the Participant to the Board and, under certain circumstances, by utilizing the assignment procedures of the Net Billing Agreements described below or making cash payments (which cash payments would be payable from the Bonneville Fund, as described herein). Under the Resolution, the Board is required to deposit the payments it receives pursuant to the Three-Party Net Billing Agreements into the Trojan General Fund. See "THE NET BILLING AGREEMENTS — *Payments After Termination*." Each Participant's ability to make required payments to the City under its Three-Party Net Billing Agreement depends on its ability to generate sufficient revenue from its electric system and the receipt of net billing credits or cash payments from Bonneville. By means of the 2005 Letter Agreement described below, Bonneville will agree that, if any Participant is unable for any reason, or fails or refuses, to pay to the Board any amount due from the Participant under its Three-Party Net Billing Agreement for which a billing credit or a cash payment to such Participant has been provided by Bonneville pursuant to the related Three-Party Net Billing Agreement, Bonneville will pay directly to the Board in cash the unpaid amount. The 2005 Letter Agreement does not apply to the Board. See "THE NET BILLING AGREEMENTS – 2005 Letter Agreement."

BONNEVILLE'S OBLIGATIONS UNDER THE NET BILLING AGREEMENTS AND THE 2005 LETTER AGREEMENT ARE NOT GENERAL OBLIGATIONS OF THE UNITED STATES OF AMERICA AND ARE NOT SECURED BY THE FULL FAITH AND CREDIT OF THE UNITED STATES OF AMERICA.

THE SERIES 2005 BONDS DO NOT IN ANY MANNER CONSTITUTE A GENERAL OBLIGATION OF THE BOARD OR OF THE CITY, OR CREATE A CHARGE UPON THE TAX REVENUES OF THE CITY, OR UPON ANY REVENUES OR PROPERTY OF THE CITY OR THE BOARD OTHER THAN THE REVENUES OF THE TROJAN PROJECT, BUT ARE A CHARGE UPON AND PAYABLE SOLELY FROM THE REVENUES OF THE TROJAN PROJECT, SUBJECT TO THE PAYMENT OF PROJECT EXPENSES. THE HOLDERS OF THE SERIES 2005 BONDS MAY ONLY LOOK FOR REPAYMENT TO SUCH REVENUES OF THE TROJAN PROJECT, SUBJECT TO THE PAYMENT OF PROJECT EXPENSES, AND MAY NOT, DIRECTLY OR INDIRECTLY, BE PAID OR COMPENSATED THROUGH THE PROPERTY OF THE CITY OR THE BOARD OR BY OR THROUGH THE TAXING POWER OF THE CITY.

THE PROJECT

The Project is located on a site along the Columbia River, approximately 35 miles north of Portland, Oregon and 5 miles south of Kelso, Washington. The Project had a nameplate capacity of approximately 1,100 megawatts, commenced commercial operation in 1976, and operated through November, 1992. PGE announced the permanent shutdown of the Trojan Project in 1993 because of a degradation of the steam generator tubes. The Project is being decommissioned pursuant to the Trojan Decommissioning Plan approved by the NRC in 1996. While the cooling tower and many Project buildings remain intact, the Project's nuclear reactor has been removed to the Hanford Nuclear Reservation, the Project's spent nuclear fuel has been stored in canisters housed at an interim dry storage facility located on the Project site, and certain office buildings on the Project site are being leased to private companies. The Trojan Decommissioning Plan assumes that most of the remaining decommissioning activities will be completed in 2005, while costs to operate and maintain the independent spent fuel storage installation ("ISFSI") will continue until at least 2019. Final site restoration activities are anticipated to begin in 2018, after PGE (as defined below) completes shipment of spent nuclear fuel to a United States Department of Energy ("US DOE") permanent repository. No such permanent repository currently exists. See "LITIGATION" for a discussion of pending litigation with respect to the storage of spent nuclear fuel at a permanent repository. The Project is subject to various government regulations and orders that affect or may affect the Project's decommissioning and other costs. See "CERTAIN INVESTMENT CONSIDERATIONS AND RISK FACTORS–Risks Related to Additional Regulatory Requirements".

Project Ownership and Trojan Operating Agreement

The Project is owned by Portland General Electric Company ("PGE"), Pacific Power & Light Company ("PacifiCorp"), and the City (acting by and through the Board), as tenants-in-common, pursuant to an Agreement for Construction, Ownership and Operation of the Trojan Nuclear Plant (the "Trojan Ownership Agreement"), dated October 5, 1970. The respective Project ownership interests (the "Ownership Shares") under the Trojan Ownership Agreement are:

PGE	67.5%
City	30.0%
PacifiCorp	2.5%

Notwithstanding the fact that PGE, the City and PacifiCorp (collectively, the "Project Owners") own undivided interests in the Project as co-tenants, the Trojan Ownership Agreement provides that each party will severally bear its Ownership Share of all obligations and liabilities relating to the Project as they arise. PGE was designated by the City and PacifiCorp to operate and maintain the Project. It continues to do so during the decommissioning phase of the Project. Certain matters may affect PGE's Ownership Share or its ability to perform its obligations under the Trojan Ownership Agreement. See "CERTAIN INVESTMENT CONSIDERATIONS AND RISK FACTORS — Risks Related to Co-Owners; Risks of Imposition of Obligations of Co-Owners on Board."

The Trojan Operating Agreement requires that PGE prepare an operating budget for each calendar year. The proposed operating budget must be submitted to the Project Owners by September 1 for their approval. The proposed operating budget must take into account the cumulative difference between payments into and expenditures from an "Operating Trust Account" up to the preceding August 1 and provide for restoration, as necessary, of the working cash fund. The proposed operating budget becomes effective unless disapproved within 30 days after submittal. Once approved, the operating budget must be changed to include, among other things, costs occasioned by an emergency or required by governmental authority. Trojan Project decommissioning and other costs for 2003, as reported by PGE to the other Project owners, were approximately $51.6 million. The operating budget for 2004 for the Trojan Project as submitted by PGE to the other Project Owners was $39.3 million. Final expenditures for 2004 were approximately $31.2 million. The Trojan Project budget for 2005 provides for expenditures of $20.6 million.

Pursuant to the Trojan Ownership Agreement, PGE established the Operating Trust Account from which the Project's decommissioning and other costs are paid. The Project Owners are required to make monthly deposits in the Operating Trust Account equal to their respective Ownership Shares of the amount budgeted for the next succeeding month in the Project's operating budget.

Regarding termination of the Project, the Trojan Operating Agreement requires PGE to sell for removal, to the highest bidders, all salable parts of the Project (except the real property underlying the generating plant and the visitors' center, which revert to PGE under the Trojan Operating Agreement). If the costs of ending the Project exceed available funds from selling the salable parts of the Project, then each Project Owner is required to pay its Ownership Share of such excess as incurred. The costs of ending the Project include the cost of decommissioning, razing all structures and disposing of the debris and meeting all requirements of Federal, state or local law relating to the safe deactivation of the plant.

DESCRIPTION OF THE SERIES 2005 BONDS

General

The Series 2005 Bonds will be dated, will bear interest at the rates, will mature in such principal amounts and at such times and be issued in such denominations at set forth on the front and inside cover of this Official Statement.

Series 2005 Bonds Not Subject to Optional Redemption

The Series 2005 Bonds are not subject to redemption prior to maturity.

Book Entry Only System

The Depository Trust Company, New York, New York ("DTC"), will act as Securities Depository for the Series 2005 Bonds. The Series 2005 Bonds will be issued as fully registered bonds registered in the name of Cede & Co. Upon issuance of the Series 2005 Bonds, a single bond, registered in the name of Cede & Co., as the nominee of DTC, will be issued for each bond maturity. See Appendix J — "THE DEPOSITORY TRUST COMPANY" for information regarding DTC and its book-entry system.

SECURITY FOR THE SERIES 2005 BONDS

General

The Series 2005 Bonds are payable as to principal and interest solely from and are equally and ratably secured solely by a lien on and pledge of the Revenues, subject to the payment of Project Expenses, in accordance with their terms and the provisions of the Resolution.

"Revenues" are defined in the Resolution to mean "all revenues, income, rents, receipts and profits derived by the City or Board from its Ownership Share of the Trojan Project." These include (i) all payments to the Board pursuant to the Net Billing Agreements, (ii) all payments to be made by the Board pursuant to the provision described in Appendix H — "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — Covenants" - under the caption "Transfer in the Amounts of Credits Received Under the Two-Party Net Billing Agreement," and (iii) all interest and other investment earnings on any moneys or investments held in any funds and accounts under the Resolution." "Project Expenses" are all of the Board's costs resulting from the City's ownership of an interest in the Trojan Project, the operation and maintenance of and renewals and replacements to the Trojan Project and the salvage, discontinuance, decommissioning, dismantling and disposition thereof, but excluding amounts which the Board is required to pay in each year into the Trojan Bond Fund or to otherwise set aside for the payment of the Bonds or any other obligations issued by the Board in connection with the Trojan Project.

Flow of Funds

The Board is required under the Resolution to deposit all Revenues of the Trojan Project into the Trojan General Fund as promptly as practicable after receipt thereof by the Board. Pursuant to the Resolution, the Board is required to apply amounts on deposit in the Trojan General Fund to the payment of Project Expenses or to the provision of reserves therefor and is required to transfer amounts remaining in the Trojan General Fund after paying or making provision for such payment monthly to the Bond Fund for the payment of debt service on the Bonds, including the Series 2005 Bonds. The Trojan General Fund is held and invested by the Board. The Trojan General Fund is separate and distinct from the Operating Trust Account established by PGE under the Trojan Ownership Agreement. See Appendix H — "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — Continuation of Trojan General Fund and Application of Revenues; Trojan Revenue Bond Fund".

The Board has covenanted in the Resolution, among other things, to: (i) deposit all "Revenues of the Electric System" in the Electric System Revenue Fund; (ii) not incur any debt, claim or other obligation or issue any bonds, notes or other evidences of indebtedness payable from the "Revenues of the Electric System" that will rank in priority over the transfers from the Electric System Revenue Fund to the Trojan General Fund required by the Resolution; and (iii) fix, establish and collect (or cause to be fixed, established and collected) rates, tolls, rents and other charges for electric power and energy and for any services or facilities sold, furnished or supplied by the Electric System or any part thereof, that are sufficient to meet its obligation to transfer money from the Electric System Revenue Fund to the Trojan General Fund and meet all other charges against the Electric System Revenue Fund. See "Appendix C — "EUGENE WATER & ELECTRIC BOARD AND ITS ELECTRIC SYSTEM" herein for certain information about the Board's Electric System.

The Board's obligation to make transfers from the Electric System Revenue Fund to the Trojan General Fund is limited to the extent of credits provided to the Board under the Two-Party Net Billing Agreement. The Board's ability to transfer moneys from the Electric System Revenue Fund to the Trojan General Fund depends upon the availability of Electric System Revenues. The availability of Electric System Revenues is based on the Board's revenues and expenses for providing electric service. Oregon law (ORS 225.210 to 225.300) requires the Board to ascertain and prescribe an electric rate or rates that will create a fund sufficient to meet the cost of maintaining and conducting the Electric System. Amounts payable by the Board to Bonneville for the cost of power, transmission and other services (including amounts subject to net billing under the Two-Party Net Billing Agreement) are treated as operating expenses of the Electric System. The Board considers such amounts, together with all other costs of the Electric System, in setting and adjusting its Electric System rates pursuant to Oregon law.

Additional Bonds

Subsequent to the issuance of the Series 2005 Bonds, the Board may issue an additional Series of the Bonds (herein defined and referred to as "Additional Bonds") for any purpose in connection with the Project by means of a Supplemental Resolution, but only upon compliance with the following conditions: (i) the Authorized Representative of the Board shall have found and determined that no Event of Default exists under the Resolution, (ii) the Board shall have determined by resolution that the City's Ownership Share of the Project will produce Revenues at least sufficient to enable the Board to meet all of its obligations under the Resolution, and (iii) the Net Billing Agreements shall be for terms extending at least to the final maturity date of the Bonds and there shall be no default existing and continuing thereunder.

Annual Budget

The Resolution requires that not less than ten days prior to the beginning of each calendar year, the Board shall prepare an Annual Budget for its Ownership Share of the Project for the ensuing calendar year. The Annual Budget is required to set forth in reasonable detail the estimated Revenues and Project Expenses for such year and shall include an estimate of all other expenditures by the Board in connection with the Trojan Project for such year. The Annual Budget is required to provide for of all Project costs and may also set forth such additional material as the Board may determine and shall contain a certificate to the effect that the Annual Budget has been prepared in accordance with the Resolution. From time to time during each calendar year the Board is required to review its estimates of Revenues and Project Expenses for such calendar year and in the event such estimates do not substantially correspond with actual Revenues or Project Expenses, or if there are at any time during any such calendar year extraordinary receipts or payments of unusual costs for the Trojan Project, the Board is required to prepare an amended Annual Budget.

Bond Resolution Rate Covenant

The Board has covenanted in the Resolution to fix, establish and collect, or cause to be fixed, established and collected, rates, tolls, rents and other charges for electric power and energy (including capability) and for any services or facilities sold, furnished or supplied by the Electric System or any part thereof, which rates, tolls, rents and charges shall be sufficient to meet the Board's obligation to transfer from the Electric System Revenue Fund to the Trojan General Fund, if and to the extent the Board receives a net billing credit pursuant to the Two-Party Net Billing Agreement, an amount equal to the amount of the credit received. The obligation to make such transfer shall be an Operating Expense of the Electric System. An amount equal to a credit so received shall be so transferred to the Trojan General Fund no later than the date payment of such amount would have been due to Bonneville if a net billing credit had not been received.

Only costs related to the Board's Ownership Share of the Trojan Project (and no other projects of the Board) may be paid from the Trojan General Fund.

Covenant Against Prior Claims on Electric System Revenues

The Board has covenanted in the Resolution that it will not incur any debt, claim or other obligation or issue any bonds, notes or other evidences of indebtedness payable from the Electric System Revenues which will rank in priority over the transfers to the Trojan General Fund of an amount equal to net billing credits received pursuant to the Two-Party Net Billing Agreement as discussed above.

No Pledge of Electric System Revenues

The Board's Electric System Revenues are not pledged to the payment of the Series 2005 Bonds, and the Series 2005 Bonds are not secured by any lien on such Electric System Revenues. The Board has covenanted to use Electric System Revenues to fund transfers into the Trojan General Fund from the Electric System Revenue Fund, as required by the Resolution, however, neither the Bondholders nor the Bond Fund Trustee have been assigned rights to, or provided with security interests in, the Electric System Revenues or any fund into which such revenues are deposited (other than the Trojan General Fund). The Board's obligation to make transfers from the Electric System Revenue Fund to the Trojan General Fund is limited to the extent of credits provided to the Board under the Two-Party Net Billing Agreement.

No Guarantee from Bonneville

Bonneville has not guaranteed the obligations of the City and the Board to make the payments and transfers required by the Resolution. Bonneville's obligation to make payments to the Board under the Two-Party Net Billing Agreement is limited. Bonneville's obligations under the Net Billing Agreements and the 2005 Letter Agreement are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. See "THE NET BILLING AGREEMENTS" herein. Bonneville has not undertaken to make payments directly to Bondholders or to the Bond Fund Trustee in the event the Board is unable to make the transfers from the Electric System Revenue Fund to the Trojan General Fund required by the Resolution, or if there is insufficient money in the Trojan General Fund or Trojan Bond Fund to pay the principal of or interest on the Series 2005 Bonds. The 2005 Letter Agreement does not pertain to the Board's obligations under the Resolution or the Two-Party Net Billing Agreement.

No Guarantee of Bonneville or Participant Obligations

Neither the City nor the Board has guaranteed the obligations of Bonneville or any Participant to make payments under the Net Billing Agreements or the 2005 Letter Agreement. Bondholders should not expect the City or the Board to use their available resources to cure a deficiency created in the Trojan General Fund on account of Bonneville's inability or unwillingness to honor its obligation under the 2005 Letter Agreement.

No Pledge of Net Billing Agreements or the Project

Neither the Net Billing Agreements nor the Project have been pledged as security for the Bonds. In the event of a default under the Resolution, the remedies provided to Bondholders and the Trustee will be limited. See Appendix H — "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION," under the heading

"Remedies" for a summary of the remedies available to Bondholders and the Bond Fund Trustee if an Event of Default occurs under the Resolution. These remedies do not include the foreclosure and sale of the Board's Ownership Share in the Project, or the sale and assignment of the Board's interests in the Net Billing Agreements.

Source of Payment Limited

THE SERIES 2005 BONDS DO NOT IN ANY MANNER CONSTITUTE A GENERAL OBLIGATION OF THE BOARD OR OF THE CITY, OR CREATE A CHARGE UPON THE TAX REVENUES OF THE CITY, OR UPON ANY REVENUES OR PROPERTY OF THE CITY OR THE BOARD OTHER THAN THE REVENUES OF THE TROJAN PROJECT, BUT ARE A CHARGE UPON AND PAYABLE SOLELY FROM THE REVENUES OF THE TROJAN PROJECT, SUBJECT TO THE PAYMENT OF PROJECT EXPENSES. THE HOLDERS OF THE SERIES 2005 BONDS MAY ONLY LOOK FOR REPAYMENT TO SUCH REVENUES OF THE TROJAN PROJECT, SUBJECT TO THE PAYMENT OF PROJECT EXPENSES, AND MAY NOT, DIRECTLY OR INDIRECTLY, BE PAID OR COMPENSATED THROUGH THE PROPERTY OF THE CITY OR THE BOARD OR BY OR THROUGH THE TAXING POWER OF THE CITY.

No Debt Service Reserve

No debt service reserve fund or reserve and contingency fund will be established with respect to the Bonds, including the Series 2005 Bonds.

THE NET BILLING AGREEMENTS

General

Bonneville has acquired the City's entire 30% Ownership Share of the Trojan Project capability (i) from the City pursuant to the Two-Party Net Billing Agreement, and (ii) from the Participants pursuant to the Three-Party Net Billing Agreements. Under the Two-Party Net Billing Agreement the City assigned a portion of its Ownership Share of Project capability to Bonneville. Under the Three-Party Net Billing Agreements the City assigned the remaining portion of its Ownership Share of the Project to the Participants which, in turn, assigned their respective shares to Bonneville. Certain provisions of the Net Billing Agreements are summarized below. Certain other provisions of the Net Billing Agreements are summarized in "INTRODUCTION — Security for the Series 2005 Bonds." The brief summaries of certain of the terms of the Net Billing Agreements set forth in this Official Statement are qualified by reference and subject to the complete terms thereof.

The Project has been terminated and, in accordance with the Net Billing Agreements, the Net Billing Agreements terminated except for those provisions that provide for the billing and payment of the costs of the Project, including all amounts which the Board is required under the Resolution to pay each year into the various funds of the Resolution for debt service and all other purposes. See "— Payments after Termination" below.

Participants' Shares

The names of the Participants, their current Participant's Shares (shown as a percentage of the City's Ownership Share), the budgeted payments under the Three-Party Net Billing Agreements during 2004, and the amounts of Bonneville's net billing obligations to each Participant and the Board during 2003 are shown in the following table. In addition to the Net Billing Agreements, the Participants also have entered into net billing agreements with Bonneville and the Washington Public Power Supply System (now known as Energy Northwest) relating to Energy Northwest's Columbia Generating Station and its Projects 1 and 3, and the

Board has entered into such an agreement with respect to Project No. 1 under which its participant's share of costs is 0.061%.

Participant	Participant's Share	2005 Budgeted Trojan Project Payments ($000)	2004 Total Net Billed Obligations* ($000)
Clatskanie Peoples' Utility District (Oregon)	18.000%	$2,327	$4,009
City of Springfield (Oregon)	6.000	776	1,337
Salem Electric (Oregon)	5.333	690	1,188
Consumers Power, Inc. (Oregon)	3.667	474	562
City of McMinnville (Oregon)	3.333	431	742
Umatilla Electric Coop. Association (Oregon)	3.333	431	742
City of Forest Grove (Oregon)	3.000	388	668
Blachly-Lane County Coop. Electric Assoc. (Oregon)	2.000	259	335
Lincoln Electric Cooperative (Washington)	2.000	259	446
City of Canby (Oregon)	1.667	216	371
City of Monmouth (Oregon)	1.667	216	371
Northern Wasco Peoples' Utility District (Oregon)	1.000	129	223
West Oregon Electric Cooperative (Oregon)	0.667	85	94
Subtotal	51.667	6,681	11,088
The Board	48.333	6,250	10,765
Bonneville Net Billing Deficiency Amounts**			420
Total	100.000%	$12,931	$22,273

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* "Net Billed Obligations" are the costs of certain generating projects met by the provision of net billing credits by Bonneville under all net billing agreements involving the related Participant or the Board. These costs include (i) the costs relating to the Ownership Share of the Trojan Project payable under the Net Billing Agreements, and (ii) the costs relating to three nuclear generating stations owned by Energy Northwest, a joint operating agency organized under the laws of the State of Washington, payable under net billing agreements that are similar to the Three-Party Net Billing Agreements. The Board is a participant in one of the Energy Northwest projects and each of the Participants is a participant in all three of the Energy Northwest projects.

** "Bonneville Net Billing Deficiency Amounts" are dollar amounts that Bonneville would otherwise have had to pay to a Participant because the aggregate dollar amount the Participant owed to the Board under the related Three-Party Net Billing Agreement and to Energy Northwest under the related net billing agreements with Energy Northwest was less than the aggregate dollar amount of purchases made by the Participant from Bonneville for power and transmission services during the subject period. Under the related net billing agreements, if a Participant has less in dollar obligations billed by and owing to Bonneville in the related net billing contract year than the Participant is obligated to pay to Energy Northwest and the Board under the related net billing agreements, Bonneville must make up such "deficiency" to the Participant by making cash payments to the Participant, subject to restrictions on the use of the Bonneville Fund. See "The Bonneville Fund and Bonneville's Priority of Payments" below.

Notwithstanding Bonneville's obligation to make payments to Participants for Bonneville Net Billing Deficiency Amounts, in 2004, Bonneville made voluntary payments directly to Energy Northwest in the amount of the Bonneville Net Billing Deficiency Amounts, $420,000. These voluntary direct payments obviated the need for Bonneville to pay such amounts to the related participant. See "Assignment of Shares; Cash Payments" below.

Payments after Termination

Notwithstanding the termination and decommissioning of the Trojan Project, cash payments and the provision of net billing credits by Bonneville and payments by Participants under the Net Billing Agreements are required (in the aggregate) to be sufficient to pay all of the Board's costs with respect to its Ownership Share of the Project. Such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by the Board, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

The Net Billing Agreements provide for the Board to provide to Bonneville and the Participants monthly accounting statements with respect to the Board's costs of the salvage, discontinuance, decommissioning and disposition or sale of the Board's Ownership Share of the Project, including amounts required to pay debt service on bonds issued to finance the Board's Ownership Share of the Project. In practice, the Board, with the acquiescence of Bonneville, continues to follow a budgeting and billing procedure similar to the procedure it followed before the Project was terminated. It prepares a proposed annual budget which includes (i) amounts required to pay the Board's obligations under the Trojan Project Ownership Agreement with respect to decommissioning, based upon information provided by PGE, (ii) the Board's requirements for debt service on bonds issued for its Ownership Share of the Project, and (iii) the Board's administrative and other costs with respect to its Ownership Share of the Project. The proposed annual budget is submitted to Bonneville for its approval. The annual budget once approved, forms the basis of the billing statements provided to Bonneville and the Participants pursuant to the Net Billing Agreements.

Assignment of Shares; Cash Payments

If Bonneville is unable to net bill the amounts to be credited by Bonneville to the Board or any Participant because the dollar obligations due Bonneville from the Board or such Participant are or are expected to be insufficient to offset Bonneville's dollar obligations to the Participant or the Board, Bonneville will endeavor to arrange for an assignment of such amounts which cannot be net billed, and the Participant or the Board shall make any such assignment so arranged. However, the Participants and the Board will have the first right to accept such assignment pro rata among those exercising such right before such an assignment is made to a customer other than one of the Participants or the Board. If Bonneville is unable to arrange for such an assignment, the affected Participant or the Board is required to make such assignment to the other Participants and the Board, who are obligated to accept it, pro rata, provided that the sum of such assignments to a Participant or the Board shall not exceed 25% of its Participant's Share of Project capability without its consent.

If all or a portion of its Participant's Share is assigned as described above, the Participant will remain liable to pay the purchase price for its Participant's Share in accordance with its Net Billing Agreement as if such assignment had not been made. Such liability of the Participant will be discharged only to the extent that the assignee of all or a portion of the Participant's Share shall pay to the Board the purchase price for the Share so assigned.

Bonneville has from time to time elected to make voluntary cash payments instead of attempting to arrange for assignments pursuant to the Net Billing Agreements. Bonneville has not waived its rights under the Net Billing Agreements to arrange for future assignments pursuant to the Net Billing Agreements and accordingly may in the future attempt to arrange for assignments in accordance with the provisions of the Net Billing Agreements before making cash payments in accordance with the Net Billing Agreements.

If assignments cannot be made in amounts sufficient to bring into balance the respective dollar obligations of Bonneville and the Participants (including the Board), and an accumulated balance in favor of a

Participant or the Board from a previous year is expected by Bonneville to be carried for an additional year, such balance and any subsequent monthly net balances that cannot be billed will be paid in cash to the Participant or the Board by Bonneville, subject to the limitations described above in "Participants' Shares" and in Appendix A — "BONNEVILLE POWER ADMINISTRATION – BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund."

2005 Letter Agreement

By a letter to be issued upon the delivery of the Series 2005 Bonds (the "2005 Letter Agreement"), Bonneville will agree with the Board that if any Participant is unable for any reason, or fails or refuses, to pay to the Board any amount due from the Participant under its Three-Party Net Billing Agreement for which a billing credit or a cash payment to such Participant has been provided by Bonneville pursuant to the related Three-Party Net Billing Agreement, Bonneville shall be obligated to pay directly to the Board in cash the unpaid amount.

The Electric System Revenues will not be available to cure deficiencies in the Trojan General Fund if Bonneville fails to honor the 2005 Letter Agreement.

Non-Payment of Board's Share

The 2005 Letter Agreement does not apply to payments to be made by the Board to the Trojan General Fund in respect of net billing credits under the Two-Party Net Billing Agreement nor does it apply to any failure of the Board to deposit cash payments as required by the Resolution. If the Board defaults in its obligation to apply moneys equal to net billing credits or cash payments therefor received from Bonneville, there is some uncertainty under the Two-Party Net Billing Agreement whether Bonneville would be obligated to provide the Board with additional billing credits or cash for costs for which it had theretofore provided net billing credits and/or cash payments. If Bonneville's provision of net billing credits and/or cash to pay costs for which Bonneville had already tendered payment discharges Bonneville's obligation with respect to such costs, it is possible that the failure of the Board to make payments or to properly apply moneys received could result in a delay in or the nonpayment of Project costs, including debt service on the Bonds. See "CERTAIN INVESTMENT CONSIDERATIONS AND RISK FACTORS".

The Bonneville Fund and Bonneville's Priority of Payments

The Bonneville Fund is a continuing indefinite appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses, including its cash payments to provide for the amount, if any, due under the Net Billing Agreements which is not paid from net billing credits. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund."

Bonneville may make expenditures from the Bonneville Fund, which shall have been included in Bonneville's annual budget submitted to Congress, without further appropriation and without fiscal year limitation, but subject to such specific directives or limitations as may be included in appropriations acts, for any purpose necessary or appropriate to carry out the duties imposed upon Bonneville pursuant to law, including making any cash payments required under the Net Billing Agreements and the 2005 Letter Agreement.

Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Ownership Share, to the extent covered by net billing credits, can be met without regard to amounts in the Bonneville Fund. Bonneville provides net billing credits under other net billing agreements in addition to the Net Billing Agreements. See "THE NET BILLING AGREEMENTS — Participant Shares" and Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — GENERAL".

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System (as described in Appendix A — "THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (i) the repayment of the appropriated Federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the United States Army Corp of Engineers ("Corps") and the United States Bureau of Reclamation ("Bureau") for costs allocated to power generation at Corps-owned and Bureau-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments relating to net billing agreements and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may only make payments to the United States Treasury from net proceeds; all other cash payments of Bonneville, including cash payments to the Board under the Two-Party Net Billing Agreement and the 2005 Letter Agreement and to the Participants under the Three-Party Net Billing Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has not deferred such payments since 1983.

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) Costs under the Net Billing Agreements and other net billing agreements as described in Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — GENERAL" to the extent covered by net billing credits, (2) cash payments out of the Bonneville Fund to cover all required payments incurred by Bonneville pursuant to law, including cash payments to the Board under the Two-Party Net Billing Agreement and the 2005 Letter Agreement and to the Participants under the Three-Party Net Billing Agreements, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury.

For further information, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Order in Which Bonneville's Costs Are Met." For a discussion of certain proposed and current direct payments by Bonneville for Federal System operations and maintenance, which payments would reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

BONNEVILLE'S OBLIGATIONS UNDER THE NET BILLING AGREEMENTS AND THE 2005 LETTER AGREEMENT ARE NOT GENERAL OBLIGATIONS OF THE UNITED STATES OF AMERICA AND ARE NOT SECURED BY THE FULL FAITH AND CREDIT OF THE UNITED STATES OF AMERICA.

ESTIMATED SOURCES AND USES

The following table sets forth the estimated sources and uses of funds in connection with the issuance of the Series 2005 Bonds and the refunding of the Series 1977 Bonds:

SOURCES:	
Series 2005 Bond Principal	$26,640,000
Original Issue Premium	1,091,204
Other Project Funds	17,892,845
TOTAL SOURCES	$45,624,049
USES:	
Refunding of Series 1977 Bonds	$45,091,018
Costs of Issuance	320,656
Underwriters Discount	212,375
TOTAL USES	$45,624,049

DEBT SERVICE REQUIREMENTS ON THE SERIES 2005 BONDS

Calendar Year	**Series 2005 Bonds Principal**	**Series 2005 Bonds Interest**	**Total Debt Service**
2005	$3,205,000	$ 464,897	$3,669,897
2006	7,435,000	1,171,750	8,606,750
2007	7,805,000	800,000	8,605,000
2008	8,195,000	409,750	8,604,750

THE CITY OF EUGENE AND THE EUGENE WATER & ELECTRIC BOARD

The City of Eugene, Oregon is a charter city operating under a charter most recently revised in 2002. Oregon law and the charter authorize the City to provide electric and water systems for serving the public within and without the City.

The City commenced utility operations in 1908 with the purchase of a privately-owned water system. In 1911, upon completion of the City's first municipal hydroelectric power plant, the City organized the Eugene Water Board to operate the City's electric and water utilities. The name of the Eugene Water Board was changed to the Eugene Water & Electric Board in 1949.

The Board is an administrative unit of the City and is responsible for operating the City's electric and water utilities. The responsibilities delegated to the Board pursuant to the city charter are conducted under the direction of an elected board of five commissioners. The commissioners and the expiration dates of their respective terms of office are as follows:

Member	Office	Expiration Date
Ron Farmer	President	December 31, 2006
Sandra Bishop	Vice President	December 31, 2008
Patrick Lanning	Commissioner	December 31, 2008
Melvin Menegat	Commissioner	December 31, 2006
John Simpson	Commissioner	December 31, 2008

The Board provides electricity to a 238-square mile area, including the City, adjacent suburban areas, and areas near the Walterville, Leaburg and Carmen-Smith hydroelectric plants. The Electric System service area in and around the City adjoins the City of Springfield's system on the east, the Emerald People's Utility District's system and the Blachly-Lane Electric Cooperative's system, both on the west, and Lane Electric Cooperative's system on the south. The Board also provides electric service to Weyerhaeuser Company's operation within the Springfield city boundary. The Board provides water service to the same general area. The Electric System served an average of 83,118 customers in 2004, and the water system served an average of 48,300 customers in 2004. See Appendix D — "FINANCIAL STATEMENTS OF THE EUGENE WATER & ELECTRIC BOARD." The Electric System and the water system are operated and accounted for as separate and independent entities.

The Board's Electric System includes the electric utility properties, assets and rights now owned by the Board, and all properties and assets constructed or acquired as renewals, replacements, additions, improvements and betterments to and extensions of such properties and assets, including facilities for the generation, transmission and distribution of electric power and energy and the production, transmission and distribution of steam, *excluding*: (i) the City's Ownership Share of the Project; and (ii) any electric utility properties, assets and rights hereafter constructed or acquired by the Board as a separate utility system, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire any such separate utility system.

The revenues and properties of the Electric System and the water system are not pledged to the payment of the Series 2005 Bonds. The Series 2005 Bonds are not secured by a lien on the Electric System Revenues. The Board's obligation to make transfers from the Electric System Revenue Fund to the Trojan General Fund is limited to the extent of credits provided to the Board under the Two-Party Net Billing Agreement. See "SECURITY FOR THE SERIES 2005 BONDS—General; Flow of Funds" and "THE NET BILLING AGREEMENTS." The Resolution requires the Board to set its rates sufficiently to pay all of its operating and power costs for the Electric System and to transfer moneys to the Trojan General Fund from the Electric System Revenue Fund to the extent the Board receives a net billing credit from Bonneville pursuant to the Two-Party Net Billing Agreement. The Board's ability to transfer moneys to the Trojan General Fund depends upon the availability of Electric System Revenues. The availability of Electric System Revenues is based upon the Board's revenues and expenses for providing electric service. Oregon law (ORS 225.210 to 225.300) requires the Board to set its electric rates so that they are sufficient to meet the cost of maintaining and conducting the Electric System.

Information concerning the Board's Electric System power supply resources and costs and the Board's rates and rate-setting practices is contained in Appendix C — "EUGENE WATER & ELECTRIC BOARD AND ITS ELECTRIC SYSTEM."

Accounting Policies and Independent Auditors

The Board's accounting policies conform to generally accepted accounting principles for public utilities and governmental units. The Board applies all applicable Governmental Accounting Standards Board (GASB) pronouncements, along with the Statements of Financial Accounting Standards Board (FASB), Accounting Principles Board Opinions, and Accounting Research Bulletins of the Committee on Accounting Procedures, unless those pronouncements conflict with or contradict GASB pronouncements.

The Board obtains an audit and examination of its accounts and financial status at least once each year pursuant to the Oregon Municipal Audit Law, ORS 297.405 to 297.555. The most recent audit report with respect to the accounts of the Board is for the calendar year ended December 31, 2004, with respect to which an unqualified opinion was rendered by PricewaterhouseCoopers LLP, independent auditors. PricewaterhouseCoopers LLP has not completed any additional auditing or review procedures subsequent to the issuance of such report with respect to the Board's operations.

A copy of the Board's audited basic financial statements for the calendar year ended December 31, 2004, is attached hereto as Appendix D. Such statements include information concerning the Electric System, the water system, the Board's Ownership Share of the Trojan Project, the Board's financial policies and controls, risk management policies, capital assets, long-term debt activity and related topics. To the extent the financial statements contain information with respect to the Project or the Series 1977 Bonds, such information is supplemented and qualified in all respects by the discussions of the Project, the Net Billing Agreements, the Board and other matters contained in this Official Statement.

THE BONNEVILLE POWER ADMINISTRATION

The information under this heading has been derived from information provided to the City by Bonneville. For detailed information with respect to Bonneville, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION" in this Official Statement.

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 30 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally-owned projects, including the Columbia Generating Station owned by Energy Northwest. Bonneville sells and/or exchanges power under contracts with over 100 utilities in the Pacific Northwest and Pacific Southwest and with several industrial customers. It also owns and operates a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest.

Bonneville's primary customer service area is the Pacific Northwest region, an area comprised of Oregon, Washington, Idaho, western Montana and small portions of California, Nevada, Utah and Wyoming (sometimes referred to herein as the "Pacific Northwest", the "Northwest," the Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville also exports power that is surplus to the needs of the Region to the Pacific Southwest, primarily to California.

Bonneville is one of four regional Federal power marketing agencies within the DOE. Bonneville is required by law to meet certain energy requirements in the Region and is authorized to acquire power resources, to implement conservation measures and to take other actions to enable it to carry out its purposes. Bonneville is also required by law to operate and maintain its transmission system and to provide transmission service to eligible customers and to undertake certain other programs, such as fish and wildlife protection, mitigation and enhancement.

CERTAIN INVESTMENT CONSIDERATIONS AND RISK FACTORS

Revenues Limited; Non-Recourse to Distribution System and other City Assets

The Board's obligation to pay the Series 2005 Bonds from Revenues after the payment of Project Expenses is subject to receipt by the Board of net billing credits or cash payments pursuant to the Two-Party Net Billing Agreement and payment by the Participants (or by Bonneville pursuant to the 2005 Letter Agreement) of amounts payable pursuant to the Three-Party Net Billing Agreements. If sufficient credits and amounts are not available through the Net Billing Agreements or the 2005 Letter Agreement to pay debt service on the Series 2005 Bonds after the payment of all Project Expenses, including all costs associated with the decommissioning of the Project, payment of debt service on the Bonds may be delayed, interrupted or not made. No assets or revenues of the Board or the City are pledged to or are available to pay debt service on the Series 2005 Bonds other than the Revenues.

Risks Related to Co-Owners; Risks of Imposition of Obligations of Co-Owners on Board

Neither PGE nor Pacificorp (or their successors) are obligated to make payments with respect to the Series 2005 Bonds.

Under the Trojan Ownership Agreement a default by a PGE or Pacificorp would not require the City to assume any of the ownership obligations of such co-owner. However, on August 19, 1997, the NRC published a "Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry" which provides that "[t]he NRC recognizes that co-owners and co-licensees generally divide costs and output from their facilities using a contractually defined, pro rata share standard. The NRC has accepted this practice in the past and believes that it should continue to be the operative practice, but reserves the right, in highly unusual situations where adequate protection of public health and safety would be compromised if such action were not taken, to consider imposing joint and several liability on co-owners of more than de minimis shares when one or more co-owners have defaulted." The NRC has denied requests for reconsideration of the policy on the issue of joint and several liability for co-owners of nuclear power plants. It cannot be determined at this time whether there could be any circumstances under which liability would be imposed on the Board with respect to the Project beyond its contractual pro rata share. While ORS 225.480 limits the Board's liability to its ownership share of costs, no assurance can be given that a court would not conclude that NRC regulations preempt State law. In the event that PGE or Pacificorp is unable to meet all of its ownership share of the total Project costs, claims might be made against the Board and the other co-owner to pay such sums. If claims were made against the Board to pay any sums not paid by another co-owner, the City believes that it has defenses against such claims. These matters, however, have not been litigated definitively to date in any federal or state court and, therefore, the results of such litigation cannot be predicted with certainty. The Board would vigorously contest any obligation to pay any Project costs imposed on the Board beyond its contractual pro rata share.

PGE has a 67.5% ownership interest in the Project. PGE has stated in its U.S. Securities and Exchange Commission Form 10-K for the fiscal year ended December 31, 2004 (the "10K") that it operates as a wholly owned subsidiary of Enron Corp. ("Enron"). The 10 K also states: "Commencing in December 2001, Enron and certain of its subsidiaries (Debtors) filed for bankruptcy under Chapter 11 of the federal Bankruptcy Code. PGE is not included in the bankruptcy, but the common stock of PGE held by Enron is part of the bankruptcy estate." The 10K contains a discussion of the status of such bankruptcy proceedings and PGE's potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. PGE has also reported in the 10K that (i) Enron and Oregon Electric, a newly-formed Oregon limited liability company financially backed primarily by investment funds managed by Texas Pacific Group, have entered into an agreement under which Enron will sell all of the issued and outstanding common stock of PGE to Oregon Electric, (ii) such sale is subject to the approval of federal and state regulatory bodies, (iii) on March 10, 2005, the Oregon Public Utility Commission issued an order in which it denied Oregon Electric's application to purchase PGE, (iv) Enron and Oregon Electric have stated that they are reviewing the order and evaluating their next steps, and (v) if PGE is not sold to Oregon Electric, Enron will either sell PGE to another buyer or distribute shares of PGE's common stock over time to the Debtors' creditors. It is also stated in the 10K that until the sale to Oregon Electric is approved, another filing related to the sale of PGE is approved, or PGE's common stock is distributed to the Debtors' creditors, the management of PGE cannot assess the impact on PGE's business and operations of a sale or the distribution of PGE's stock to the Debtors' creditors.

Senate Bill 1008 ("SB 1008") was introduced and read in the Oregon Senate on March 3, 2005. SB 1008 would, if enacted, establish a public corporation called Oregon Community Power as a part of the government of the State of Oregon. SB 1008, as drafted, provides that the primary mission of Oregon Community Power would be to provide reliable, low-cost electricity to consumers in its service territory. SB 1008 directs Oregon Community Power to enter into negotiations with PGE or other persons to negotiate the disposition of the electric utility assets of PGE. Oregon Community Power would be prohibited from acquiring the service territory of any other electric utility. SB 1008 has been referred to the Business and Economic Development, General Government and Ways and Means Committees of the Oregon Senate and a public hearing was held on March 10, 2005. No representations can be made regarding the legal effect of SB 1008 if enacted, or the likelihood that the Oregon Legislature will enact SB 1008. The Board or other entities may submit for consideration amendments to SB 1008 or other legislation that is relevant to the ownership or acquisition of PGE.

Recovery through rates of PGE's share of decommissioning costs for the Project is subject to review and approval of the Oregon Public Utilities Commission ("OPUC"). The 10K contains a discussion of the status of OPUC approval of PGE's share of decommissioning costs for the Project. No assurance can be given that additional OPUC review or authorization will not be required with respect to PGE's share of decommissioning costs.

The impact of the Enron bankruptcy and the potential sale, or distribution of shares, of PGE on PGE's willingness or ability to continue to perform under the Trojan Ownership Agreement cannot be determined at this time. In particular, it cannot be determined whether PGE will be acquired by Oregon Electric; how the acquisition, if approved by OPUC and other regulatory agencies, will affect the ability of PGE to meet all of its ownership obligations regarding the Project, or whether PGE will be able to meet all of its current and future decommissioning obligations from the Trojan Decommissioning Fund, financial reserves or available insurance.

Certain information set forth herein has been obtained from PGE's IOK. PGE did not participate in the preparation of this Official Statement. The City, the Board and Bonneville make no representations regarding the accuracy of information provided by PGE in its filings with the SEC. PGE's filings with the SEC are not incorporated into this Official Statement by reference. PGE is currently required to file annual, quarterly, and other reports with the U.S. Securities and Exchange Commission ("SEC"). References to PGE and any information derived from PGE reports are subject to the more complete statements regarding such matters set forth in such PGE reports, including reports made after the date of this Official Statement. These reports should be available on the SEC's website (www.sec.gov) and at the SEC's public reference room in Washington, D.C. Copies of these documents can be requested, upon payment of a duplicating fee, by writing to the SEC. The SEC can be contacted at (800) SEC-0330 for further information on the operation of the public reference rooms.

Risks Related to Additional Regulatory Requirements

The co-owners contracted with the US DOE for permanent disposal of the Project's spent nuclear fuel in federal facilities. Significant delays are expected in the USDOE acceptance schedule of spent fuel from domestic utilities, with no federal repository expected to be available until at least 2010. See "LITIGATION". If no federal repository is permitted or if the availability of a federal repository is otherwise significantly delayed, additional regulatory requirements may be imposed to address the ISFSI and storage of spent fuel and other decommissioning activities at the Project site. Any such regulatory requirements or additional decommissioning activities may have the effect of increasing Project costs.

Additionally, in response to the terrorist attacks of September 11, 2001, the NRC imposed interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process. The interim compensatory security measures are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in April 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. On August 18, 2004, the NRC issued an order that modifies the current license for the Trojan ISFSI to require compliance with certain specified additional security measures ("August 2004 Order"). The August 2004 Order was effective immediately. In the August 2004 Order, the NRC stated that it had determined that certain additional security measures were required to address the current threat environment in a consistent manner throughout the nuclear ISFSI community. These additional security measures supplement existing regulatory requirements and will remain in effect until the NRC determines otherwise. It is uncertain whether additional requirements will be imposed by the NRC on the Trojan ISFSI. Until the full NRC requirements associated with all orders are determined, it is not known whether any related implementation costs will impact the Project's decommissioning costs and related funding requirements.

Risks Related to Catastrophic Loss or Other Incidents

Pursuant to the Trojan Ownership Agreement, certain risks are insured. Nevertheless, no assurance can be given that the Board will not be subject to additional Project expenses that are not covered by insurance in the event of a catastrophic loss or other incident such as natural disasters, terrorist attacks, or a release or incident related to the spent fuel stored on site with respect to the Project or additional liability beyond its contractual pro rata share of the Project as the result of a co-owner's unwillingness or inability to pay its ratable share of such additional costs.

Risk of Events Pertaining to the Board

There is uncertainty under the Two-Party Net Billing Agreement whether Bonneville would be obligated to provide additional billing credits and cash payments for costs associated with any liability or obligation of PGE or PacifiCorp that is imposed on the City. The City would seek credit and payments for all Project costs under the Net Billing Agreements, including any costs imposed on the Board beyond its contractual pro rata share, should the City be required to pay any sums not paid by a co-owner of the Project. The Board believes that Bonneville would be required to net bill or otherwise pay the Board for sums advanced by the Board. Bonneville has not recognized such a repayment obligation.

No assurance can be given regarding the treatment or application of Revenues in the event the City files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law or is subject to a state statute governing insolvent governmental entities.

No assurance can be given that the revenues available from the Electric System will be equal to or exceed any net billing credit received under the Two-Party Net Billing Agreement in the event of the occurrence of unforeseen events.

Bonds Not General Obligations of United States, State or City

Bonneville's obligations under the Net Billing Agreements and the 2005 Letter Agreement are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The Series 2005 Bonds are not a general obligation of the State of Oregon or of any political subdivision thereof. Neither the full faith and credit nor the taxing power of the City is pledged to the payment of the Series 2005 Bonds.

The Initiative Process

The Oregon Constitution, Art. IV, Sec. 1, reserves to the people of the state the initiative and referendum power pursuant to which measures designed to amend the state Constitution or enact legislation can be placed on the statewide general election ballot for consideration by the voters. Over the past decade, Oregon has seen active use of the initiative and referendum process, with initiative measures being proposed on a variety of constitutional and statutory topics. Under Oregon law, there are no express restrictions on the kind of measures that may be placed on the ballot, other than a requirement that the proposal "shall embrace one subject only and matters properly connected therewith." The Board cannot predict whether future initiative measures that may have an adverse effect on the Board's operations and financial position will be approved by voters.

TAX MATTERS

In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville ("Special Tax Counsel"), based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2005 Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986 and Section 103 of the Internal Revenue Code of 1986 (the "Code") and is exempt from State of Oregon and Multnomah County, Oregon personal income taxes. Special Tax Counsel is of the further opinion that interest on the Series 2005 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings when calculating corporate alternative minimum taxable income. In rendering its opinion, Special Tax Counsel has relied on the opinion of Bond Counsel as to the validity of the Series 2005 Bonds and the due authorization and issuance of the Series 2005 Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E hereto, subject to the matters discussed below.

Series 2005 Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series 2005 Bonds. The Board has made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the Series 2005 Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2005 Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2005 Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken), or events occurring (or not occurring), or any other matters coming to Special Tax Counsel's attention after the date of issuance of the Series 2005 Bonds may adversely affect the value of, or the tax status of interest on, the Series 2005 Bonds.

Certain requirements and procedures contained or referred to in the Tax Certificate, and other relevant documents may be changed and certain actions (including, without limitation, defeasance of the Series 2005 Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. Special Tax Counsel expresses no opinion as to any Series 2005 Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice or approval of counsel other than Orrick, Herrington & Sutcliffe LLP.

Although Special Tax Counsel is of the opinion that interest on the Series 2005 Bonds is excluded from gross income for federal income tax purposes and is exempt from State of Oregon and Multnomah County, Oregon personal income taxes, the ownership or disposition of, or the accrual or receipt of interest on, the Series 2005 Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel expresses no opinion regarding any such other tax consequences.

Future legislation, if enacted into law, or clarification of Title XIII of the Tax Reform Act of 1986 or of the Code, may cause interest on the Series 2005 Bonds to be subject, directly or indirectly, to federal, state or local income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislation or clarification may also affect the market price for, or marketability of, the Series 2005 Bonds. Prospective purchasers of the Series 2005 Bonds should consult their own tax advisers regarding any pending or proposed federal tax legislation, as to which Special Tax Counsel expresses no opinion.

The opinion of Special Tax Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2005 Bonds for federal, state and local income tax purposes. It is not binding on the Internal Revenue Service ("IRS") or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of the Board, or about the effect of future changes in the Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. The Board has covenanted, however, to comply with the requirements of the Code.

Special Tax Counsel's engagement with respect to the Series 2005 Bonds ends with the issuance of the Series 2005 Bonds, and, unless separately engaged, Special Tax Counsel is not obligated to defend the Board or the Beneficial Owners regarding the tax-exempt status of the Series 2005 Bonds in the event of an audit examination by the IRS or by state or local authorities. Under current procedures, parties other than the Board and its appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the federal audit examination process. Moreover, because achieving judicial review in connection with a federal audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which the Board legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2005 Bonds for audit, or the course or result of such audit, or an audit of Series 2005 Bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2005 Bonds, and may cause the Board or the Beneficial Owners to incur significant expense.

LITIGATION

No Litigation as to Series 2005 Bonds

To the knowledge of the Board, no litigation, inquiry, or investigation, at law or in equity, is pending or threatened against the Board wherein an unfavorable decision, ruling or finding would have a materially adverse effect upon the transactions contemplated by this Official Statement, the bond purchase contract, the Resolution or the Net Billing Agreements or the validity of the Series 2005 Bonds.

Spent Fuel Litigation

On January 6, 2004, PGE, the Board and PacifiCorp (collectively, the "Project Owners") filed a civil action in the United States Court of Federal Claims against the United States Department of Energy ("US DOE") for breach of a contract entitled "Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste, US DOE Contract No. DE-CR01-83NE4406, Audit No. 35911 ("SNF Contract"). The Complaint alleges, among other things, that the US DOE breached the SNF Contract by failing to accept delivery and dispose of the Project's spent nuclear fuel and/or high-level radioactive waste (collectively "SNF"). Under the SNF Contract, entered into on June 13, 1983, the Project Owners agreed to purchase US DOE services for disposal of the SNF produced at the Project. The Project Owners made payments to the US DOE under the terms of the SNF Contract while the Project was operating. Those payments totaled approximately $104.9 million. When the Project ceased operating in 1993, the Project Owners' contractual obligation to continue making payments to the US DOE for the removal of the SNF ceased. In return for the SNF Contract payments by the Project Owners, the US DOE agreed to begin disposing of the SNF produced at the Project beginning no later than January 31, 1998. The SNF Contract also provides that disposal of the SNF removed from a nuclear power reactor that has been shut down permanently for whatever reason may be given priority.

The US DOE has stated that it will not be able to take any SNF from any utility until 2010 at the earliest, due to among other things, difficulties in preparing permanent geological disposal sites to store the SNF. Under the US DOE's latest schedule, the last of the Project's SNF would not be taken until 2039. The Complaint alleges that had disposal begun in January 1998, and the Project and other shut-down plants been given their due priority, the last of the Project's SNF would have been taken by 2002. In the interim, the Project Owners constructed an Independent Spent Fuel Storage Installation ("ISFSI") rather than retain the SNF in its wet storage facility. The ISFSI is a dry storage facility utilizing concrete casts for containment. The ISFSI is designed to reduce operation and maintenance costs for storing the SNF. In the Complaint, the Project Owners estimate that as a result of the US DOE's breach of the SNF Contract, the Project Owners have been damaged in an aggregate amount of at least $217 million. This sum includes estimated costs associated with the construction, continued operating and maintenance of the ISFSI facilities, and the deprivation of the use of the real property required for construction of the ISFSI facilities and all of the real property comprising the Project site.

There are currently pending in the United States Court of Federal Claims more than 20 similar actions filed by other utilities against the US DOE for breach of SNF disposal contracts similar to the SNF Contract between the Project Owners and the US DOE. On April 16, 2003, the Court of Federal Claims ordered that six of these pending cases be designated "lead" or "accelerated" cases for resolution of dispositive motions. The plaintiffs of the lead cases are Yankee Atomic Electric Company; Connecticut Yankee Atomic Power Company; Maine Yankee Atomic Power Company; Florida Power & Light Company; Indiana Michigan Power Company; and Commonwealth Edison Company.

The Court of Federal Claims also ordered that the remaining SNF disposal contract cases on file as of April 4, 2003 be stayed unless affirmatively ordered to proceed by the presiding judge in any individual case. It is anticipated that resolution of the lead cases will resolve the threshold legal issue of the US DOE's liability to the utilities for breach of the various SNF disposal contracts. On January 5, 2005, the United States Court of Federal Claims issued an order that discovery in the case would be stayed until June 30, 2005.

On or about August 5, 2004, a settlement was reached between the United States Department of Justice ("US DOJ") and Exelon, and Exelon's subsidiaries Commonwealth Edison and AmerGen Energy Company (collectively "Exelon"). Exelon had entered into contracts with the US DOE for the acceptance of SNF. The Exelon contracts required the US DOE to start accepting the SNF not later than January 31, 1998. When the US DOE failed to accept the waste, Exelon filed suit for damages in the U.S. Court of Federal Claims. The settlement agreement generally provides that Exelon agrees to dismiss the Exelon lawsuits with prejudice in exchange for certain annual payments from the US DOE for Exelon's costs incurred in storing the

SNF. The total amount to be paid by the US DOE under the settlement agreement will depend on when the US DOE actually commences acceptance of the SNF. It is unclear why the US DOJ chose to settle with Exelon or what impact, if any, the settlement will have on the claims filed by the Trojan Project co-owners.

State of California Litigation

On February 14, 2005, the State of California, through the California Department of Water Resources ("DWR"), filed, but did not serve the Board with, a "Complaint For Rescission, Restitution, Damages and Declaratory Relief" ("Complaint") against the Board in the Superior Court of the State of California for the County of Sacramento. The Complaint alleges that DWR was compelled to enter into numerous energy transactions with the Board at excessive prices during the period of January 17, 2001 through June 20, 2001. DWR seeks rescission of certain transactions, restitution and an unspecified amount of damages. Based on the Board's initial review, the Board believes that valid defenses are available against the allegations made in the Complaint. The Board intends to vigorously contest the allegations made in the Complaint. Without further factual analysis or discovery, no predictions can be offered at this time as to the eventual outcome of this proceeding.

CERTAIN LEGAL MATTERS

Legal matters incident to the authorization, issuance, and sale of the Series 2005 Bonds by the Board on behalf of the City are subject to the final approving opinion of Hawkins Delafield & Wood LLP, New York, New York, Bond Counsel to the Board. The opinion of Bond Counsel will be substantially in the form contained in Appendix E. Certain tax matters will be passed on by Orrick, Herrington & Sutcliffe LLP, New York, New York, Special Tax Counsel to Bonneville. The opinion of Special Tax Counsel will be in substantially the form attached hereto as Appendix F. Certain legal matters will be passed upon for the Board by Cable, Huston, Benedict, Haagensen & Lloyd and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by their counsel, Foster Pepper & Shefelman PLLC, Spokane, Washington. Any opinion of such firm will be rendered solely to the Underwriters, will be limited in scope, and cannot be relied upon by investors without the written consent of such firm.

Bond Counsel will also render a supplemental opinion with respect to the Net Billing Agreements. A copy of the form of such opinion is also contained in Appendix E.

UNDERWRITING

The Series 2005 Bonds are being purchased by the Underwriters at a price of $27,518,828.14 (representing the principal amount of the Series 2005 Bonds plus premium of $1,091,203.55 less an underwriting discount of $212,375.41). The bond purchase contract by and between the Underwriters and the Board provides that the Underwriters will purchase all of the Series 2005 Bonds if any are purchased.

RATINGS

Moody's Investors Service, Inc. and Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc., have assigned their municipal bond ratings of "Aaa" and "AA-," respectively, to the Series 2005 Bonds. A rating reflects only the views of the rating agency and an explanation of the significance of such ratings may be obtained from the respective rating agencies. There is no assurance that such ratings will continue for any given period of time or that they will not be revised downward or withdrawn entirely by either or both of the rating agencies, if, in their judgment, circumstances so warrant. Any downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Series 2005 Bonds.

CONTINUING DISCLOSURE

To enable the Underwriters to comply with the provisions of Rule 15c2-12 of the SEC, the Board and Bonneville will execute Continuing Disclosure Agreements the terms of which are summarized in Appendix I. Neither the City, the Board nor Bonneville has failed to comply with any previous continuing disclosure undertaking made pursuant to Rule 15c2-12.

ADDITIONAL INFORMATION

The information contained in this Official Statement is subject to change without notice and no implication should be derived therefrom or from the sale of the Series 2005 Bonds that there has been no change in the affairs of the City, the Board or Bonneville from the date hereof. Additional information may be obtained from James H. Origliosso at the Board, telephone (541) 484-3753.

MISCELLANEOUS

Any statement in this Official Statement involving matters of opinions, whether or not expressly so stated, are intended as such, and not as representations of fact. This Official Statement is not to be construed as an agreement or contract between the Board and the purchasers or holders of any Series 2005 Bonds.

EUGENE WATER & ELECTRIC BOARD

By s/ James H. Origliosso
Title: Director, Customer and
Financial Services

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to the City of Eugene, Oregon, acting by and through the Eugene Water & Electric Board (the "Issuer" or "City") by Bonneville for use in the Official Statement, dated April 7, 2005, furnished by the Issuer (the "Official Statement") with respect to its Trojan Nuclear Project Revenue Bonds, Refunding Series 2005 (the "Series 2005 Bonds"). Such information is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2005 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, is true and correct and does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this Appendix A and in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

GENERAL

Bonneville was created by an act of Congress in 1937 to market electric power from the Bonneville Dam located on the Columbia River and to construct facilities necessary to transmit such power. Congress has since designated Bonneville to be the marketing agent for power from all of the federally-owned hydroelectric projects in the Pacific Northwest. Bonneville, whose headquarters are located in Portland, Oregon, is one of four regional federal power marketing agencies within the U.S. Department of Energy ("DOE"). Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 30 federal hydroelectric projects, most of which are located in the Columbia River Basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Bureau"). These projects have an expected aggregate output of roughly 9,000 average megawatts under median water conditions. Bonneville also has acquired and markets power from several non-federally owned and operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by Energy Northwest (a joint operating agency organized and existing under the laws of the State of Washington) and having a rated capacity of approximately 1100 megawatts. Bonneville sells, purchases and exchanges firm power, non-firm energy, peaking capacity and related power services. Bonneville also constructed and operates and maintains a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities and power marketers.

Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the 300,000 square-mile service area is approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville markets the majority of this power to over 100 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service Bonneville provides to DSIs has diminished substantially relative to levels from the 1940s through the 1990s. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," may result in payments by Bonneville to the exchanging utilities if the applicable power rates for Federal Columbia River Power System ("Federal System") power are lower than the utilities' respective average system cost of meeting their residential and small farm power loads. The primary participants in the Residential Exchange Program historically have been investor-owned utilities in the Region (the "Regional IOUs").

The Transmission System Act placed Bonneville on a self-financing basis, meaning that Bonneville pays its costs from revenues it receives from the sale of power and the provision of transmission and other services, which Bonneville provides at rates that seek to produce revenues that recover Bonneville's costs, including certain payments to the

United States Treasury. Bonneville's rates for the foregoing services are subject to approval by the Federal Energy Regulatory Commission ("FERC") on the basis that, among other things, they recover Bonneville's costs. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates." Bonneville may also issue and sell bonds to the United States Treasury and use the proceeds thereof to fund certain activities established under Federal law.

In 1996, after certain national regulatory initiatives to promote competition in wholesale power markets were announced, Bonneville separated its power marketing function from its transmission system operation and electric system reliability functions. While Bonneville is a single legal entity, it conducts its business as separate business lines: the "Power Business Line" and the "Transmission Business Line." See "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines."

Bonneville's cash receipts from all sources, including from both its transmission and power-marketing business lines, must be deposited in the Bonneville Fund, which is a separate fund within the United States Treasury and which is available to pay Bonneville's costs. In accordance with the Transmission System Act, Bonneville must make expenditures from the Bonneville Fund as "shall have been included in annual budgets submitted to Congress, without further appropriation and without fiscal year limitation, but within such specific directives or limitations as may be included in appropriation acts, for any purpose necessary or appropriate to carry out the duties imposed upon [Bonneville] pursuant to law."

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the Corps and the Bureau for certain costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2004 payment responsibility to the United States Treasury of $1.053 billion (including $346 million in principal payments in advance of due dates under the Debt Optimization Proposal as described in this Appendix A) in full and on time. Bonneville has made all payments to the United States Treasury in full and on time since 1984. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Proposal."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Two-Party Net Billing Agreement and the Three-Party Net Billing Agreements, and cash payments, if any, under the 2005 Letter Agreement, and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may only make payments to the United States Treasury from net proceeds; all other cash payments of Bonneville, including cash deficiency payments if any under Two-Party Net Billing Agreement and the Three-Party Net Billing Agreements and cash payments, if any, under the 2005 Letter Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. The Two-Party Net Billing Agreement, the Three-Party Net Billing Agreements and the 2005 Letter Agreement, each of which secures payment of the Series 2005 Bonds. See Official Statement under the heading "SECURITY FOR THE SERIES 2005 BONDS."

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has not deferred such payments since 1983.

In addition to the net billing agreements between Bonneville and the Issuer, and among Bonneville, the Issuer and certain other named Participants with respect to the Issuer's ownership interest ("Ownership Share") of the Trojan Nuclear Project (the "Project") (such net billing agreements are referred to herein collectively as the "Trojan Net Billing Agreements"), Bonneville is party to over three hundred separate net billing agreements relating to three other nuclear generating stations owned and operated by Energy Northwest, two of which projects were terminated prior to construction completion, and one of which is operating (collectively, the "Energy Northwest Net Billed Projects").

Under these other net billing agreements (the "Energy Northwest Net Billing Agreements"), related Bonneville customers ("Energy Northwest Participants") make payments to Energy Northwest to meet the costs of the Energy Northwest Net Billed Projects. As is the case with the Trojan Net Billing Agreements, under the Energy Northwest Net Billing Agreements, Bonneville provides to the Energy Northwest Participants payment credits against monthly power and transmission bills issued by Bonneville. Subject to certain limitations and exceptions, the net billing credits are provided by Bonneville in amounts up to the payments the Energy Northwest Participants make to Energy Northwest. Once the Energy Northwest Participants have satisfied their respective payment obligations to Energy Northwest in a related Energy Northwest Net Billing Agreement contract year (July 1 through June 30), and Bonneville has provided the Energy Northwest Participants equivalent dollar amounts of credits in such year, such Participants resume paying their respective power and transmission bills directly to Bonneville. The cash payments to Bonneville continue until the next annual billing cycle begins under the respective Energy Northwest Net Billing Agreements, although it is possible that Energy Northwest may reinitiate net billing in a contract year to cover unexpected costs. While the Trojan Net Billing Agreements and Energy Northwest Net Billing Agreements employ a similar net billing crediting procedure, the contract year used for the Trojan Project runs from January 1 to December 31. See "SECURITY FOR THE SERIES 2005 BONDS—Annual Budget" in the Official Statement.

The Energy Northwest Net Billing Agreements have had and are expected to have the effect of reducing Bonneville's revenues in cash from the beginning of each Energy Northwest fiscal year (beginning on July 1) until the time in that year that the Energy Northwest Net Billed Project costs budgeted for such year are collected from the Energy Northwest Participants and other sources. Thus, typically, during the fourth quarter of a given Bonneville fiscal year (October 1 through September 30) and early portions of the following Bonneville fiscal year, a substantial amount of payments in cash that Bonneville would otherwise receive from its power and transmission sales to the Energy Northwest Net Billing Participants are in effect paid directly by such Participants, under their net billing agreements, to Energy Northwest to pay Energy Northwest Net Billed Projects' costs. As a group, such Participants constitute Bonneville's largest customer base. The period in a Bonneville fiscal year during which net billing is operative varies by Participant and project, but, in general depends on the amounts of and rates for power and transmission service purchased from Bonneville by the various Participants in the Net Billed Projects, and on the costs of the related projects.

The Issuer is an Energy Northwest Net Billing Participant with respect to one of the Energy Northwest Net Billed Projects, and the other Trojan Net Billing Participants are Energy Northwest Net Billing Participants with respect to all three of the Energy Northwest Net Billed Projects.

DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION

For much of its history, Bonneville had a high degree of certainty that its revenues from power and transmission services would be sufficient to recover all of its costs without concern for substantial price competition from other suppliers. In the mid-1990's, competition increased in the wholesale electricity industry. Bonneville was particularly affected because its business, both power marketing and the provision of bulk transmission, is primarily wholesale. This increase in competition was due to a number of factors, including electric power deregulation advanced under the National Energy Policy Act of 1992 ("EPA-1992"). As a result of deregulation actions relating to Western energy markets, hydroelectric generating conditions primarily relating to the amount of precipitation in the West, natural gas prices, variations in load levels due to changes in economic activity and the weather, and a variety of other factors, wholesale power prices in the West have been very volatile in the past several years. Prices peaked in the fiscal year 2000-2001 period at levels that were many multiples of historical prices but declined in fiscal year 2002. Prices have since risen in subsequent fiscal years. Electric power prices affect both the revenues Bonneville receives from disposing of electric power and the expenses Bonneville incurs to meet contracted electric power loads.

Subscription Strategy, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments

At or slightly before the end of Bonneville's fiscal year 2001, which ended on September 30, 2001, all of Bonneville's then existing long-term, in-Region power sales contracts with Preference Customers and DSIs, and all of Bonneville's settlements with Regional IOUs to whom Bonneville is required by law to provide Residential Exchange Program benefits, expired. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program." In anticipation of the expiration of such contracts and during the unprecedented volatility in Western power markets described in this Appendix A, Bonneville and its Regional customers negotiated new long-term power sales and related agreements for the period beginning on or slightly before October 1, 2001. Under this "Subscription Strategy," Bonneville entered into five- and ten-year power sales contracts with 135 Regional Preference Customers and into five-year power sales contracts with a small number of DSI companies. Bonneville also entered into settlement contracts with all six of the Regional IOUs to settle Bonneville's obligations under the Residential Exchange Program through fiscal year 2011.

The aggregate power sales commitment initially undertaken by Bonneville under these agreements, together with certain pre-existing surplus firm power sales and related obligations, exceeded by roughly 3200-3300 average megawatts the aggregate amount of power from Federal System generating resources, which was estimated at the time to be roughly 8000 firm average megawatts, and certain contract purchases. To meet a portion of this difference, Bonneville entered into a number of power purchases to augment Federal System generation resources ("Augmentation Purchases"). Given the very high energy prices prevailing at the time, Bonneville subsequently negotiated a number of load reduction agreements with its Regional customers (including DSIs, Regional IOUs and Preference Customers) in lieu of making additional Augmentation Purchases. Under the load reduction agreements Bonneville agreed to pay customers to reduce the amount of power Bonneville otherwise was obligated to provide under related Subscription power sales agreements. Most of the load reductions occurred in fiscal years 2002 and 2003; however, about 700 average megawatts of the load reductions are in effect through fiscal year 2006.

In view of the foregoing Augmentation Purchases and load reduction agreements, lowered expectations regarding Regional load growth, and declining expectations that aluminum company DSIs will meet their power purchase obligations, Bonneville believes that it may have a relatively modest amount of firm power in excess of actual firm loads in fiscal year 2006 and may have some market price risk in making discretionary power sales of that excess firm power. In fiscal year 2005, water conditions are substantially below average and, depending on runoff and precipitation conditions, loads and other factors in the remainder of operating year 2005, it is possible that Bonneville may have to make power purchases to meet contracted loads in such year. In fiscal years 2000-2001, coincident with the development of the power sales and related contracts under the Subscription Strategy, Bonneville developed and proposed power rates for such Subscription agreements for the five-year period beginning October 1, 2001 (the "2002 Final Power Rates"). The 2002 Final Power Rates are comprised of "base rates" and certain rate level adjustment mechanisms. FERC approved the proposed 2002 Final Power Rates, including the base rates and the rate level adjustment mechanisms, on July 21, 2003.

The "base rates" are subject to three intra-rate-period rate level adjustments that are triggered upon the occurrence of specified circumstances. The base rates are between approximately 1.93 cents per kilowatt-hour and 2.30 cents per kilowatt-hour, excluding transmission and depending on type of service, and are at levels similar to those in effect for like service in the fiscal year 1997-2001 rate period. While the base rates are low relative to the cost of most other power generation, the triggering of the rate level adjustment mechanisms (which in effect create variable rate levels for affected power sales and related transactions) has had the effect of raising Bonneville's rates substantially over the base rates.

Under the first of the rate adjustment mechanisms, the Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), Bonneville makes semi-annual adjustments to rate levels tied to the direct cost of certain Augmentation Purchases and certain load reduction agreements entered into to address the increment of loads assumed by Bonneville under the Subscription Strategy.

Under the second rate level adjustment, the Financial Based Cost Recovery Adjustment Clause ("FB-CRAC"), Bonneville increases rate levels on an annual basis to obtain limited amounts of revenues in a fiscal year if Bonneville forecasts that its Power Business Line accumulated net revenues will be below identified fiscal year-end threshold levels.

Under the third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause ("SN-CRAC"), Bonneville reserved the ability to impose one or more separate rate level increases in order to recover costs on a temporary basis if certain conditions indicating that Bonneville is not adequately recovering its costs are met. In early calendar year 2003, Bonneville determined that the conditions triggering an SN-CRAC proceeding had been met and later developed and formally proposed a specific SN-CRAC rate level adjustment to be effective for fiscal years 2004 through 2006 (the "2004 SN-CRAC Rate Level Adjustment"). Under the 2004 SN-CRAC Rate Level Adjustment, related power rate levels are adjusted for a fiscal year primarily on the basis of the Power Business Line's third quarter projected net revenues for the respective prior fiscal year. Certain costs in a number of major cost categories are capped and are not automatically recovered through the 2004 SN-CRAC Rate Level Adjustment. The maximum revenue recoverable through the 2004 SN-CRAC Rate Level Adjustment through fiscal year 2006 is capped at $290 million per year.

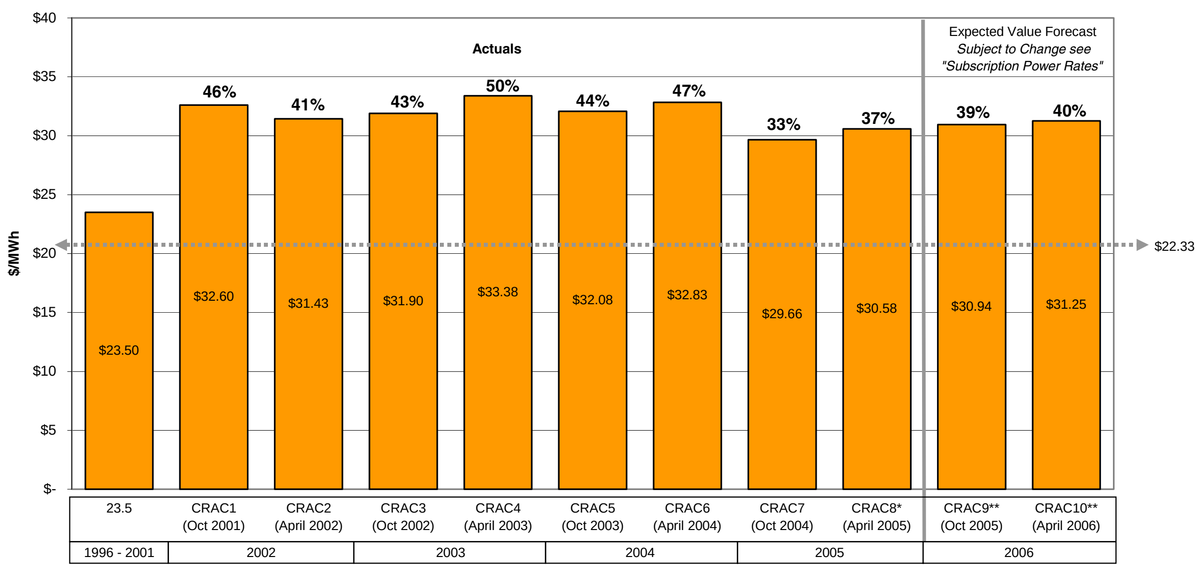
The following Table depicts the cumulative effects of the base rate and the three rate adjustment mechanisms on Bonneville's average Subscription power rate levels for full requirements service at Bonneville's Priority Firm ("PF") power rate on both a historical and forecast basis. See "POWER BUSINESS LINE—Customers and Other Power Contract Parties of Bonneville's Power Business Line."

With respect to fiscal year 2005 rate levels, the following table reflects the effects of certain rate level determinations to be in effect in such year, made by Bonneville in September 2004. On September 16, 2004, Bonneville set the FB-CRAC and SN-CRAC rate level adjustments to be in effect in fiscal year 2005. For fiscal year 2005 the SN-CRAC rate level adjustment was set at zero percent of base power rates for Subscription power sales. By contrast, the SN-CRAC rate level adjustment in effect in fiscal year 2004 was set at about 10 percent of such base rates. The fiscal year 2005 FB-CRAC rate level adjustment was set at its maximum of roughly 11 percent of base power rates, which is about the same as is in effect in fiscal year 2004.

After taking into account the base power rates and the effects of the FB-CRAC, SN-CRAC and LB-CRAC rate level adjustments, Bonneville now expects that average rate levels in effect in fiscal year 2005 for Subscription power sales will be approximately \$30-\$31 per megawatt hour, depending on type of service and excluding transmission. By contrast, such rates were slightly below \$33 per megawatt hour in the last six months of fiscal year 2004, depending on type of service and excluding transmission. Bonneville expects power rate levels to increase slightly in the six months beginning April 1, 2005 to reflect anticipated increases in the LB-CRAC rate level adjustment for such period. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Residential Exchange Program Obligations" herein.

The power rates portrayed below do not include requirements service provided to certain small Preference Customers who committed to purchase power from Bonneville early in the Subscription process at power rates that are not subject to the cost recovery adjustment mechanisms. The depiction below portrays only full requirements service offered under Bonneville's Subscription power rates schedules and does not portray rate levels related to Slice of the System, Partial Requirements, DSI and Regional IOU Exchange Settlements. Nonetheless, Bonneville believes it illustrates the impacts of the rate adjustments in the current rate period and provides a basis to compare Subscription power rates with rate levels in the prior rate period.

Bonneville Full Requirements Power Rate Levels 1996-2006,
Including Acual and Forecasted Cumulative Rate Level Adjustments in FY 2002-2006



*Each bar represents the average full requirments rate for the indicated period, taking into account the LB CRAC, FB CRAC and SN CRAC. The percentage above each bar is the adjusted rate over May base rates due to the CRAC adjustments. The forecasts rates are as of December 17, 2004.

In developing the 2004 SN-CRAC Rate Level Adjustment proposal, Bonneville estimated that it would provide Bonneville with an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time over the three fiscal years beginning October 1, 2003. Such estimates were based on a number of forecasts and assumptions.

Under current internal forecasts of future market prices, Bonneville believes that its Subscription power rates levels, as adjusted by the various rate level adjustment mechanisms, on average in fiscal years 2005-2006 will remain below market prices for such period based on similar power products. Bonneville believes that its Subscription power rates will not exceed the cost of new natural gas fired generation when shaped to serve load similar to the shaping ability of the Federal System. Such belief is based on market, rate and other forecasts that are subject to many variables most of which are not within Bonneville's control. For a more detailed description of Bonneville's proposal for power rates applicable to Subscription power sales, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates."

FERC has approved the 2002 Final Power Rates and the 2004 SN-CRAC Rate Level Adjustment. The approvals are the subject of legal challenges in the Ninth Circuit Court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge" and "BONNEVILLE LITIGATION—Fiscal Year 2004 SN-CRAC Adjustment Litigation."

In addition, several of Bonneville's customers and customer groups filed separate suits in the Ninth Circuit Court challenging Bonneville's decision that the conditions specified in the 2002 Final Power Rates enabling Bonneville to initiate the proceedings necessary for implementing the SN-CRAC by developing an 2004 SN-CRAC Rate Level Adjustment had been met. See "BONNEVILLE LITIGATION—Industrial Customers of the Northwest Utilities, et al. v. Bonneville Power Administration."

Bonneville believes that its ability to recover power costs during the remaining term of the five-year rate period ending September 30, 2006 is and will be a function of several key risks: (i) the level and volatility of market prices for electric power in western North America, which define the revenues Bonneville receives from discretionary sales of energy; (ii) the level of Bonneville's load serving obligation after voluntary load reductions and negotiated power buy-backs; (iii) water conditions in the Columbia River drainage, which determine the amount of power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (iv) changes in fish protection requirements, which could be the source of substantial additional expense to Bonneville and could further affect the amount and value of hydroelectric energy produced by the Federal System; and (v) operating costs, generally.

Bonneville's Fiscal Year 2004 Financial Results

According to final audited results for the fiscal year ended September 30, 2004 ("Fiscal Year 2004"), Bonneville made payments to the United States Treasury of $1.053 billion, which included full and timely payments of Bonneville's scheduled United States Treasury repayment responsibilities and $346 million in advance amortization of debt under the Debt Optimization Proposal. For a description of the Debt Optimization Proposal see "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Proposal." Bonneville also recorded net revenues of approximately $504 million, although absent the net revenue effects of the Debt Optimization Proposal and other debt management actions relating to Energy Northwest, Bonneville had net revenues of about $66 million. The fiscal year end net revenue amount of $66 million also excludes $89 million in positive non-cash, mark-to-market accounting adjustments under the Financial Accounting Standards Board ("FASB") Statement of Accounting Standard No. 133 ("SFAS 133"). By way of contrast to fiscal year 2004, in fiscal year 2003, Bonneville made payments to the United States Treasury in the amount of $1.057 billion. This amount included $315 million in advance amortization of debt under the Debt Optimization Proposal. In addition, in fiscal year 2003, Bonneville recorded net revenues of about $37 million after excluding the positive net revenue effects of such advance amortization and the positive non-cash, mark-to-market accounting adjustments under SFAS 133.

A number of elements contributed to Bonneville's financial performance in fiscal year 2004. Runoff conditions in Operating Year 2004 (July 30, 2003 to August 1, 2004) were about 77 percent of average, representing the fifth consecutive year of below average runoff conditions in the Region. These lower than average runoff conditions led to reduced amounts of discretionary power sales from hydroelectric generation, and somewhat lower amounts of such sales, when compared to fiscal year 2003 when runoff conditions were about 85 percent of average. Several factors partially offset the financial effects of lower than average runoff conditions. First, while amounts received by Bonneville under the LB-CRAC rate level adjustment continued to decline with a decline in the costs of Augmentation Purchases and related actions, Bonneville received enhanced revenues of about $83.5 million under the first year of the 2004 SN-CRAC Rate Level Adjustment. Second, Bonneville once again triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2004, receiving revenue in amounts roughly equivalent to those resulting from the LB-CRAC in fiscal year 2003. The FB-CRAC rate level adjustment allowed Bonneville to recover about $102 million in additional revenues in fiscal year 2004, after taking into account certain effects related to the Slice of the System contracts described in this Appendix A. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001." Third, in fiscal year 2004, Bonneville received a total of about $77 million of United States Treasury repayment credits, most of which are derived under section 4(h)(10)(C) of the Northwest Power Act. These credits are provided to reimburse Bonneville for certain fish and wildlife costs incurred by Bonneville, including power purchases made by Bonneville that are attributable to the effects of operating the hydroelectric system for the benefit of fish. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal

Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." Fourth, net interest expense borne by Bonneville declined by about $61 million (or, 18 percent), in each case when compared to fiscal year 2003.

In addition, Bonneville closed fiscal year 2004 with $638 million in fiscal year-end financial reserves as compared to $511 million at the end of fiscal year 2003 and $188 million at the end of fiscal year 2002. Bonneville's financial reserves include cash and "deferred borrowing." Deferred borrowing represents amounts that Bonneville is authorized to borrow from the United States Treasury for expenditures that Bonneville has incurred to date but the borrowing for which Bonneville has elected to delay. Several primary reasons contributed to the fiscal year 2004 increase in year-end reserves despite modest adjusted net revenues and low runoff conditions. First, revenues in cash to Bonneville at the end of fiscal year 2004 were relatively greater because net billing of Energy Northwest's budgeted costs for its fiscal year 2005 (which began on July 1, 2004) was fulfilled much earlier in Energy Northwest's fiscal year than had been the case in the past. This resulted in Bonneville's receiving comparatively greater cash payments from Energy Northwest Net Billing Participants in the later portion of Bonneville's fiscal year 2004, which led to higher fiscal year end financial reserves at the end of Bonneville's fiscal year 2004. Second, Bonneville obtained higher than forecasted prices for discretionary power sales. Third, Bonneville had higher than forecasted earnings on reserves in the Bonneville Fund. Fourth, fiscal year end financial reserves reflected about $62 million in funds held in the Bonneville Fund at the end of the fiscal year for other Federal agencies in connection with conservation efficiency programs Bonneville is assisting in and about $28 million in construction payments received by Bonneville for certain transmission facilities owned by others. Such amounts are typically held by Bonneville for short periods. For a discussion of year-to-year financial results see "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results."

Fiscal Year 2005 Developments

Unaudited Quarterly Report for the Three Months Ended December 31, 2004.

Bonneville's unaudited quarterly report for the three months ended December 31, 2004, ("Fiscal Year 2005 First Quarter") indicates that Bonneville's net revenues for such period decreased to $118 from $171 million when compared to the same period in fiscal year 2004 ("Fiscal Year 2004 First Quarter"), after excluding the effects of SFAS 133 accounting adjustments. For a discussion of SFAS 133 see "—Bonneville's Fiscal Year 2004 Financial Results." Fiscal Year 2005 First Quarter operating revenues showed little change from the same period in fiscal year 2004; however, Federal operations and maintenance increased by $53 million, a 24 percent increase, and non-Federal project debt service increased by $20 million, or about 31 percent, offset to a degree by a decline in purchase power of about $11 million, or eight percent. The comparative increase in such operating expenses was caused by increased fuel purchases for the Columbia Generating Station, and increased fish and wildlife operations and maintenance expense. The nonfederal project debt service increase reflects events in the prior fiscal year when certain debt service reserve funds at Energy Northwest were replaced by surety agreements, allowing some Energy Northwest debt service in Fiscal Year 2004 First Quarter to be paid with the reserve fund amounts that became available upon the substitution. While operating revenues showed little net change in Fiscal Year 2005 First Quarter when compared to Fiscal Year 2004 First Quarter, a $17 million increase in Power Business Line sales revenues was offset by a $6 million decrease in transmission sales revenues, increased mark to market losses under SFAS 133 and slight declines in comparative 4(h)(10)(C) fish credits and miscellaneous revenues. For further information regarding Fiscal Year 2005 First Quarter unaudited results see Appendix B-2.

Year End Financial Forecast for Fiscal Year 2005.

Current forecasts prepared outside of Bonneville, but relied on by Bonneville, indicate that streamflow and snowpack conditions in the Columbia River basin will be below average in operating year 2005 (ending August 1, 2005). The projections indicate that, based on current dry conditions in the basin, runoff may be between 65 percent and 71 percent of average in operating year 2005 (ending August 1, 2005). The low water conditions are expected to result in diminished amounts of discretionary power sales and diminished revenues therefrom in fiscal year 2005.

With the current year being the sixth consecutive year of lower than average Pacific Northwest precipitation, hydro conditions are such that Bonneville expects that it may have to make some power purchases in fiscal year 2005 to meet loads. Low water conditions are also expected to reduce surplus power sales revenues for the fiscal year from what Bonneville had expected in setting the 2004 SN-CRAC Rate Level Adjustment for fiscal year 2005. If Bonneville were to have to make substantial power purchases at the high power prices currently prevailing in the market, Bonneville's financial condition in fiscal year 2005 could be adversely affected. Notwithstanding the foregoing, Bonneville is managing its exposure to market purchases and expects that it will meet its fiscal year 2005 United States Treasury repayment obligation on time and in full. The amounts and prices of power purchases could affect whether and the extent to which Bonneville would use the 2004 SN-CRAC Rate Level Adjustment to increase power revenues in fiscal year 2006 to cover any revenue shortfalls from market purchases and reduced secondary energy sales in fiscal year 2005.

Near the end of August 2005, Bonneville will determine whether and the extent to which it will employ the 2004 SN-CRAC Rate Level Adjustment and FB-CRAC in fiscal year 2006. The determinations will depend in substantial part on then-projected year-end financial reserve forecasts for fiscal year 2005. Since Bonneville is unable to ascertain fiscal year 2005 year-end financial reserves and numerous other factors that would be considered in such determinations, Bonneville is unable to predict with certainty the rate effects of the 2004 SN-CRAC Rate Level Adjustment and FB-CRAC in fiscal year 2006. Bonneville's preliminary projections are that a fully implemented 2004 SN-CRAC Rate Level Adjustment would, if necessary, increase revenues by roughly $290 million in aggregate in such year. Bonneville expects that a fully implemented FB-CRAC will be employed in fiscal year 2006, and will yield about $115 million in such year, which is slightly more than was obtained under the FB-CRAC in fiscal year 2004.

President's Fiscal Year 2006 Budget.

The President's Fiscal Year 2006 Budget includes a proposal for legislation that calls "for certain nontraditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville's] statutory debt limit." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Nonetheless, the budget provides that the proposal would only affect those transactions occurring after enactment of the legislation. In addition, the Department of Energy has agreed that the proposed legislation will not affect Bonneville's ability to participate in the refinancing of debt it secures pursuant to transactions that Bonneville entered into prior to the date the proposed legislation takes effect.

The President's Fiscal Year 2006 Budget also includes a proposal for legislation "to very gradually bring [the federal power marketing administrations', including Bonneville's] electricity rates closer to average market rates throughout the country." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Bonneville is unable to predict whether such legislation will be introduced in, or enacted into law by, Congress.

Power Marketing After Fiscal Year 2006

Bonneville currently has about 1000 average megawatts of Augmentation Purchases, which will decline to about 800 average megawatts by fiscal year 2006 before expiring at or near the end of fiscal year 2006. In addition, all of the remaining contractually-committed, take-or-pay power purchases by aluminum company DSIs will expire at the end of fiscal year 2006. (As part of the Subscription process, Bonneville had originally agreed to sell in aggregate to such DSIs about 1500 average megawatts of power for the five years ending September 30, 2006. Bonneville is currently selling only about 200-300 average megawatts to DSIs because of contract amendments and suspensions and DSI bankruptcies and insolvencies.)

Moreover, in developing the Subscription Strategy in calendar years 1999-2001, Bonneville assumed that it would meet through physical power sales about 2200 average megawatts of Regional IOU residential and small farm loads after fiscal year 2006 under certain settlements that Bonneville entered into with the six Regional IOUs with respect to the Residential Exchange Program. As provided in such settlements (the "Residential Exchange Settlement Agreements"), Bonneville has exercised certain contract rights to meet its Residential Exchange Settlement Agreement obligations through the payment of monetary benefits rather than through physical sales of power to Regional IOUs after fiscal year 2006. The Residential Exchange Settlement Agreements and the related agreements under which Bonneville exercised the right to provide only monetary benefits thereunder after fiscal year 2006 are currently being challenged in litigation. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Finally, while a large portion of the existing Regional Preference Customer Subscription power sales contracts are in effect through fiscal year 2011, about 800 average megawatts of such loads are under contract only through fiscal year 2006. Bonneville's Final 2002 Power Rates will expire at the end of fiscal year 2006. Expectations of rate levels in the period after fiscal year 2006 will affect whether such customers increase or decrease the amount of load they place on Bonneville.

In view of the foregoing and other circumstances, Bonneville faces some uncertainty with regard to the amount of power load Bonneville will be required to meet after fiscal year 2006, and hence the amount of power it may have to obtain in addition to existing Federal System generating resources. Bonneville is currently engaged in a discussion with customers and other interested parties in the Northwest Region (the "Regional Dialogue"). The Regional Dialogue seeks to address Bonneville's role in meeting Regional electric power load in the future. In the context of the Regional Dialogue, in July 2004, Bonneville published a document entitled, "Regional Dialogue—Bonneville Power

Administration's Policy Proposal for Power Supply Role for Fiscal Years 2007-2011" (the "Draft Strategy"). Under the Draft Strategy, Bonneville has indicated to Regional customers its concerns that it not be placed in the position of attempting to acquire a substantial portion of the Region's power needs, as occurred in calendar year 2001 during the West Coast energy crisis. Bonneville stated that it would prefer to achieve these objectives by limiting the incremental load obligations Bonneville would bear above existing Federal System generating resources.

As a means of balancing its statutory obligation to meet electric power load placed on it by Preference and Regional IOU customers and its historical power sales relationship with DSI customers with the goal of low, stable power rates, Bonneville would prefer to have customers in the Region assume the role of meeting their own incremental power needs. Under the Draft Strategy, Bonneville would propose to meet only electric power load placed on it by Preference Customers and Federal agencies in roughly the same amount as is currently the case. Bonneville would not propose to meet either DSI or Regional IOU loads. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads." At present, Bonneville assumes that sales to Preference Customer and Federal agencies will equal slightly more than currently-contracted amounts and that Bonneville will continue to serve a similar amount of load during the 2007-2011 fiscal year period, with some increase to accommodate expected load growth of certain Preference Customers. Bonneville projects that such load will exceed firm Federal resources modestly, given the expected generating capability of the Federal System, with a projected deficit of about 15 average megawatts in fiscal year 2007 increasing to about 190 average megawatts by fiscal year 2011.

As a supplemental tool to help manage the risk of additional load being placed on Bonneville, the Draft Strategy provides that Bonneville would consider a proposal to limit the amount of firm power sales Bonneville makes at embedded cost rates to roughly the output of the existing Federal System. One means of implementing this approach would be to use a "tiered rate" design for Subscription power sales in the period after 2006. Under tiered rates, costs of new power purchases above the existing Federal System generating resources would not be melded with the comparatively low embedded costs of Federal System resources. Rather, the costs of the new power purchases would be separately recovered under an additional power rate or rate mechanism. To the extent a customer's purchases from Bonneville would be allocated for recovery under such a rate or rate mechanism, then the customer would bear the costs of the related incremental power purchases.

The Draft Strategy proposes that Bonneville not plan to sell power to DSIs in the period after fiscal year 2006; however, the Draft Strategy also proposes that Bonneville provide qualifying DSIs with financial payments roughly approximating the economic value of about 500 megawatts of Federal System power as determined by reference to then applicable power rates charged to Preference Customers and market prices. Under the Draft Strategy, any such benefits would be targeted to DSIs that operate, that are creditworthy and that have fully met their take or pay obligations under their Subscription contracts. Under the Draft Strategy, Bonneville would provide these benefits only if such actions actually enable aluminum production and maintain Pacific Northwest jobs. "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—DSI Loads."

Notwithstanding the direction of the Draft Strategy, the ultimate load obligations that Bonneville will assume will depend on a number of factors, including the outcome of the Regional Dialogue, and hence are uncertain. Bonneville does not anticipate finally resolving its load obligations in the post-fiscal year 2006 period until some time during fiscal year 2005. If Bonneville were to enter into physical power sales obligations to Regional IOUs to effect the Residential Exchange Settlement Agreements and/or to DSIs or others, without corresponding reductions in power sales to Regional Preference Customers, Bonneville could have larger generating resource deficits. This could increase the amount of power purchases that Bonneville would have to make, perhaps substantially.

POWER BUSINESS LINE

Description of the Generation Resources of the Federal System

Generation

Bonneville has statutory obligations to meet certain electric power loads placed on it by certain Regional customers. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." To meet these loads Bonneville relies on an array of power resources and power purchases, which, together with the Bonneville-owned transmission system and certain other features, constitute the Federal System. The Federal System includes those portions of the federal investment in the Regional hydroelectric projects that have been allocated to power generation. Such projects were constructed and are operated by the Corps or the Bureau. The Federal System also includes power from non-federally-owned generating resources, including but not limited to the Columbia Generating Station and contract purchases from other power suppliers.

Federal Hydro Generation

Hydropower from federally-owned hydroelectric projects currently supplies approximately 73% of Bonneville's firm power supply. Bonneville also has acquired a small amount of power from non-federally-owned hydroelectric projects. Bonneville's large resource base of hydropower results in operating and planning characteristics that differ from those of major utilities that lack a substantial hydropower base. See the table entitled "Operating Federal System Projects for Operating Year 2006."

The amount of electric power produced by a hydropower-based system such as the Federal System varies with annual precipitation and weather conditions. This variability has led Bonneville to classify power it has available into two types, firm power and seasonal surplus energy (as described below) based on certainty of occurrence.

Bonneville defines "firm power" as electric power that (i) is continuously available from the Federal System even during the most adverse water conditions, and (ii) is useful for meeting Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e*., the worst low-water period on record for the Columbia River Basin. Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity and firm energy. Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2006, the Federal System, including firm energy purchases, would be capable of producing about 9580 average megawatts of firm energy under certain assumptions of low water conditions. In conducting loads and resources evaluations Bonneville utilizes the term "operating year," meaning the twelve calendar months beginning each August 1. See the following table "Operating Federal System Projects For Operating Year 2006."

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most water years. Bonneville estimates that in most months its peaking capacity, for long-term planning purposes, will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because most new resources added to meet firm energy needs will also contribute more peaking capacity. As a result, Bonneville's resource planning, to the extent Bonneville may need additional resources to meet its load obligations, focuses on the need to develop sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal-, gas-, oil- and nuclear-based generating systems must focus their resource planning on having enough peaking capacity to meet peak loads.

Bonneville markets most of its energy on a firm basis. However, the amount of energy that the Federal System can produce varies from period to period and depends on a number of factors, including weather conditions, streamflows, storage conditions, flood control needs, and fish and wildlife requirements.

In general, for long-term resource planning purposes Bonneville estimates the amount of electric power it will acquire to meet loads above the firm power that the Federal System is expected to generate under certain low water conditions. For ratemaking and financial planning purposes however, Bonneville takes into account the amount of electric power it expects to have available to market based on average water conditions. The energy that Bonneville has to market above critical water assumptions in a specified period is referred to as seasonal surplus energy. The amount of seasonal surplus energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2006, assuming average water conditions (median water flows), the Federal System is estimated to generate an annual energy surplus of about 2310 average megawatts. In wet water conditions (high water flows) the amount of annual energy surplus could be as much as 3870 average megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small.

Under the Slice of the System contracts for the ten years beginning October 1, 2001, Slice customers purchased from Bonneville, for their requirements, an aggregate 22.63 percent proportionate interest of the output of the Federal System at a power rate intended to recover the same proportion of identified Federal System generating costs. This purchase includes firm power and what would otherwise be seasonal surplus energy from the Federal System in the same proportion. See "—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads." Thus, Bonneville believes that its power sales revenues from seasonal surplus energy are somewhat less subject to the impact of hydroelectric generation variability and market prices than was the case prior to the commencement of sales under the Slice of the System contracts.

The Corps and the Bureau operate the federally-owned hydroelectric projects in the Region to serve multiple statutory purposes. These purposes may include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection and power generation. Non-power purposes have placed requirements on operation of the reservoirs and have thereby limited hydropower production. Bonneville takes into account the non-power requirements and other factors in assessing the amount of power it has available to market from these projects.

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table estimates the operation of the Federal System under the Pacific Northwest Coordination Agreement ("PNCA"). The PNCA defines the planning and operation of Bonneville, U.S. Pacific Northwest utilities and other parties with generating facilities within the Region's hydroelectric system. The hydro-regulation study incorporated measures from the National Oceanographic and Atmospheric Administration Fisheries ("NOAA Fisheries") biological opinions relating to the Columbia River and tributaries dated December 2000 ("2000 Biological Opinion"), and a U.S. Fish and Wildlife Service ("Fish and Wildlife Service") biological opinion issued in 2000, for the Snake River and Columbia River projects. These measures include increased flow augmentation for juvenile fish migrations in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the Lower Snake and Columbia dams to provide for non-turbine passage routes for juvenile fish migrants, and additional flows for Kootenai River white sturgeon in the spring. As new biological opinions, such as the 2004 Biological Opinion (see "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line —Fish and Wildlife—Endangered Species Act—2000 and 2004 Biological Opinions") and similar constraints are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in the availability of Federal hydropower under all water conditions.

Other Generating Resources

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station, an 1150 megawatt nuclear generating station owned and operated by Energy Northwest. The Columbia Generating Station has the largest capacity for energy production of the non-federal resources. The Columbia Generating Station has a two-year maintenance and refueling schedule and refueling is scheduled to occur in Operating Year 2005. Accordingly, for Operating Year 2006, the estimated output of the Columbia Generating Station assumes no scheduled downtime for refueling and maintenance. In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. The amount of power purchased under these contracts increased substantially from prior years as Bonneville used such contracts to obtain electric power needed to meet the increased loads taken on by Bonneville under the Subscription Strategy.

Operating Federal System Projects For Operating Year 2006

In all years, the energy generating capability of the Federal System's hydroelectric projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, streamflow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a fifty-year record of river flows based on the period from 1929-1978 for planning purposes. During this historical period, low water conditions ("Low Water Flows") occurred in 1936-37, median water conditions ("Median Water Flows") occurred in 1957-58 and high water conditions ("High Water Flows") occurred in 1973-74. Bonneville estimates the energy generating capability of Federal System hydroelectric projects in an Operating Year (August 1 to July 30) by assuming that these historical water conditions were to occur in that Operating Year and making adjustments in the expected generating capability to reflect the current physical capacity operating limitations and current stream flow requirements. Energy generation estimates are further refined to reflect factors unique to the subject Operating Year such as initial storage reservoir conditions.

The following table shows, for Operating Year 2006, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows, Median Water Flows and High Water Flows. The same forecasting procedures are also used for non-federally-owned hydroelectric projects. Thermal projects, the output of which does not vary with river flow conditions, are estimated using current generating capacity, plant capacity factors, and maintenance schedules.

Operating Federal System Projects For Operating Year 2006[1]

Project	Initial Year in Service	No. of Generating Units	January Capacity (Peak MW)[2]	Maximum Energy (aMW)[3]	Median Energy (aMW)[4]	Firm Energy (aMW)[5]
United States Bureau of Reclamation Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	6,234	3,147	2,462	1,952
Hungry Horse	1952	4	361	126	102	77
Other Bureau Projects[6]		16	225	164	156	130
1. Total USBR Projects		53	6,820	3,437	2,720	2,159
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,535	1,668	1,340	1,066
John Day	1968	16	2,484	1,474	1,101	800
The Dalles including Fishway[7]	1957	24	2,078	1,073	826	600
Bonneville including Fishway	1938	20	1,059	597	542	364
McNary	1953	14	1,127	738	693	521
Lower Granite	1975	6	930	453	340	218
Lower Monumental	1969	6	923	443	311	220
Little Goose	1970	6	928	440	320	215
Ice Harbor	1961	6	693	379	266	137
Libby	1975	5	566	302	221	168
Dworshak	1974	3	444	234	189	126
Other Corps Projects[8]		20	398	294	269	225
2. Total USACE Projects		153	14,163	8,097	6,422	4,660
3. Total USBR and USACE Projects (line 1 + line 2)		**206**	**20,985**	**11,534**	**9,142**	**6,819**
Non-Federally-Owned Projects						
Columbia Generating Station[9]	1984	1	1,150	1,000	1,000	1,000
Other Non-Federal Hydro Projects[10]		5	32	59	47	45
Other Non-Federal Projects[11]		12	65	121	121	121
4. Total Non-Federally-Owned Projects		**18**	**1,247**	**1,180**	**1,168**	**1,166**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases[12]		**n/a**	**1,369**	**1,596**	**1,596**	**1,596**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**224**	**23,601**	**14,310**	**11,906**	**9,581**

Source: 2003 Pacific Northwest Loads and Resources Study, Bonneville, December 2003.

(1) Operating Year 2006 is August 1, 2005 through July 31, 2006.

(2) January capacity is the maximum generation to be produced under Low Water Flows in megawatts of capacity. January is a benchmark month for the system peaking capability because of the potential for high peak loads during January due to winter weather.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows in average megawatts of energy. The hydro-regulation study incorporates measures from the National Oceanographic and Atmospheric Administration Fisheries ("NOAA Fisheries") Biological Opinion dated December 2000, and the U.S. Fish and Wildlife Service's 2000 Biological Opinion (2000 Biological Opinion) for the Snake River and Columbia River projects. The effects of the 2004 Biological Opinion will be incorporated into future hydro-regulation studies, if and to the extent the effects of such biological opinion are different than assumed under the 2000 Biological Opinion. See "—Certain Statutes and Other Matters

Affecting Bonneville's Power Business Line —Fish and Wildlife—Endangered Species Act—2000 and 2004 Biological Opinions."

(4) Median energy capability is the estimated amount of hydro energy to be produced using Median Water Flows, in average megawatts of energy.

(5) Firm energy capability is the estimated amount of hydro energy to be produced using Low Water Flows, in average megawatts of energy.

(6) Other Bureau Projects include: Palisades (1957), Anderson Ranch (1950), Chandler (1956), Green Springs (1960), Minidoka (1909), Black Canyon (1925) and Roza (1958).

(7) The Dalles Project is portrayed here for convenience as including the Dalles Fishway Project of 4 megawatts of peaking capacity and 3 average megawatts of energy. The Dalles Fishway Project in fact is non-Federally-owned.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954) and Lost Creek (1975).

(9) Columbia Generating Station has a two-year maintenance and refueling schedule. For Operating Year 2005, the estimated output of the Columbia Generating Station was reduced to reflect scheduled maintenance and refueling. For Operating Year 2006 the Columbia Generating Station estimated output assumes no outage for maintenance and refueling.

(10) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Mission Valley's Big Creek (1981), Lewis County PUD's Cowlitz Falls (1994), and the City of Idaho Falls' Idaho Falls Project (1982).

(11) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's Wauna Cogeneration Project (1996) (formally James River Wauna), the State of Idaho DWR's Clearwater hydro (1998) and Dworshak Small Hydro (2000) projects. U.S. Park Service's Glines Canyon (1927) and Elwah (1910) hydro projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing and Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, and a share of the City of Ashland's solar project. Calpine's Fourmile Hill Geothermal project has been postponed to October 1, 2007.

(12) Bonneville Contract Purchases include: Subscription Strategy Augmentation Purchases and other contracts by Bonneville for power from both inside and outside the Region, including Canada.

Customers and Other Power Contract Parties of Bonneville's Power Business Line

Historically, Bonneville has had power sales and related contracts with four main classes of customers: Preference Customers, DSIs, Regional IOUs and extra-Regional customers. Bonneville also sells relatively small amounts of power to several federal agencies within the Region. The revenues derived from these customers provide Bonneville with a large portion of the funds needed to pay its costs. For information regarding the relative amounts of customer revenue and other information, see the table entitled "Federal System Statement of Revenues and Expenses" under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data." Bonneville also earns revenues from the provision of transmission service to the foregoing and other customers. See "TRANSMISSION BUSINESS LINE—Bonneville's Transmission System."

Credit risk may be concentrated to the extent that one or more groups of counterparties, including purchasers and sellers, in power transactions with Bonneville have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to the circumstances which relate to other market participants which have a direct or indirect relationship with such counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, defaults by counterparties occur from time to time. To date, no such default has had a material adverse effect on Bonneville. Bonneville continues to actively monitor the creditworthiness of counterparties with whom it executes wholesale energy transactions and uses a variety of risk mitigation techniques to limit its exposure where it believes appropriate.

Preference Customers

Preference Customers, which consist of qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, are entitled to a statutory preference and priority ("Public Preference") in the purchase of available Federal System power. These customers are eligible to purchase power at Bonneville's favorable "Priority Firm Rate" (or "PF Rate") for most of their loads, and as a class are Bonneville's principal customer base. Under Public Preference, Bonneville must meet a Preference Customer's request for available Federal System power in preference to a competing request from a non-preference entity for the same power. In the opinion of Bonneville's General Counsel, the Public Preference does not compel Bonneville to lower the offered price of uncommitted surplus Bonneville power to Preference Customers before meeting a competing request at a higher price for such uncommitted power from a non-preference entity.

Direct Service Industrial Customers

Bonneville may, but is not required to, offer to sell power to a limited number of DSIs within the Region for the purchase of power for their direct consumption. For several years prior to 1995, Bonneville's annual DSI firm loads averaged approximately 2800 average megawatts. Through the implementation of the Subscription Strategy, Bonneville signed contracts with eight DSI companies to serve about 1500 average megawatts of loads for the five years beginning October 1, 2001; however, the amount of power now being purchased by the DSIs is substantially less than the initially contracted amount. See "Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—DSI Loads."

Regional Investor-Owned Utilities

As part of Bonneville's Subscription Strategy, Bonneville entered into certain agreements, as amended, with all six of the Regional IOUs in settlement of Bonneville's statutory obligation to provide benefits under the Residential Exchange Program for specified periods beginning October 1, 2001. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program," "—Power Marketing in the Period After Fiscal Year 2001," "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data," "—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates" and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Bonneville provides firm power to the Regional IOUs under contracts other than long-term firm requirements power sales contracts. Bonneville also sells substantial amounts of peaking capacity to Regional IOUs.

Exports of Surplus Power to the Pacific Southwest

Bonneville sells and exchanges power via the Pacific Northwest-Pacific Southwest Intertie (the "Southern Intertie") transmission lines to Pacific Southwest utilities, power marketers and other entities, which use most of such power to serve California loads. These sales and exchanges are composed of firm power and non-firm energy surplus to Bonneville's Regional requirements. Exports of Bonneville power for use outside the Pacific Northwest are subject to a statutory requirement that Bonneville offer such power for sale to Regional utilities to meet Regional loads before offering such power to a customer outside the Region. However, in the opinion of Bonneville's General Counsel, Bonneville is not required to reduce the rate of proposed export sales to meet a Northwest customer's request if the proposed export sale is at a higher FERC-approved rate than the Northwest customer is willing to pay.

In addition, Bonneville's contracts for firm energy and peaking capacity sales outside the Region include, as required by the Regional Preference Act, recall provisions that enable Bonneville to terminate such sales, upon advance notice, if needed to meet Bonneville customers' power requirements in the Region. With certain limited exceptions, Bonneville's sales of Federal System power out of the Region are subject to termination on 60 days' notice in the case of energy and on 60 months' notice in the case of peaking capacity. These rights help Bonneville assure that the power needs of its Regional customers are met. Power exchange contracts are not required to contain the Regional recall provisions.

In 1995, in view of the Regional load diversification away from Bonneville that was then occurring, Congress enacted a law that authorizes Bonneville to sell for export out of the Region a limited amount of power unencumbered by the Regional Preference recall rights. Bonneville entered into a number of such excess federal power contracts that have remaining terms requiring Bonneville to export power in declining amounts through fiscal year 2007. Bonneville does not expect to have substantial new amounts of such excess federal power to sell during the remainder of the five-year rate period ending September 30, 2006.

Pacific Southwest utilities typically account for the greatest share of purchases of seasonal surplus energy from Bonneville and these sales account for the greatest share of revenues from Bonneville's exports. The amount of seasonal surplus energy that Bonneville has available to export depends on precipitation and other power supply factors in the Northwest, the available transmission capacity of the Southern Intertie, the attributes of restructured power markets in the Pacific Southwest and other factors that may constrain exports notwithstanding the availability of power.

While Bonneville designs its power rates, including its rates for out-of-Region power sales, to recover its costs, it does so in some cases with flexible price levels that enable Bonneville to make additional sales in a competitive marketplace. Revenues that Bonneville obtains from exporting power out of the Region depend on market conditions and the resulting prices. These revenues are affected by the weather and other factors that affect demand in the Pacific Southwest and the cost and availability of alternatives to Bonneville's power. The cost of alternative power is frequently dependent on other electric energy suppliers' resource costs such as the cost of hydro, coal, oil and natural gas-fired generation. Bonneville believes that if its power sales in the Region were to decline, any resulting surplus of power could be sold to the Pacific Southwest. Such sales may be limited, however, by Southern Intertie capacity and other factors.

Effect on Bonneville of Developments In California Power Markets in 1991-2001

California power markets experienced historically high power prices and volatility in the period 1999-2001. For much of that period, the California investor-owned utilities (the "Cal-IOUs"), were faced with having a cap on the rates that they could charge their customers while being required to purchase virtually all of their power requirements at prices that were multiples of the rates they could charge.

The weakened financial positions of the Cal-IOUs, particularly Pacific Gas & Electric ("PG&E"), which filed for protection under federal bankruptcy laws in April 2001, and Southern California Edison ("SCE"), also affected the financial condition of two entities with central roles in the restructuring of California's electric power industry. One such entity is the California Independent System Operator ("Cal-ISO"), a nonprofit entity that operates, but does not own, most transmission in the state and is responsible for assuring reliable transmission to the Cal-IOUs and others. By far the largest users of the Cal-ISO's services and hence the largest revenue sources for the Cal-ISO were the Cal-IOUs. Defaults by PG&E and SCE in payments for energy and transmission resulted in concerns by energy suppliers that the Cal-ISO was not a creditworthy supplier. In July 2003, PG&E Energy Trading – Power L.P. ("PGET"), a power marketing affiliate of PG&E and an energy trading counterparty of Bonneville's, also filed for bankruptcy protection. See "BONNEVILLE LITIGATION—PGET Bankruptcy."

Another such entity is the nonprofit California Power Exchange ("Cal-PX"), which suspended operations on January 31, 2001, but was theretofore responsible for operating a day-ahead power exchange through which the Cal-IOUs were obligated to purchase virtually all of their power requirements. As a consequence of the continued operation of the exchange during periods of unprecedented high market prices when the Cal-IOUs' retail rates could not recover the market prices for power, the Cal-PX has substantial outstanding payment obligations due from the Cal-IOUs. The Cal-PX filed for bankruptcy protection in March 2001.

Bonneville entered into certain power sales through the Cal-PX for which Bonneville is due payment but has not yet been paid. Bonneville ceased selling into the Cal-PX in December 2000. In addition, through January 10, 2001, Bonneville sold power and related service to the Cal-ISO to help it maintain transmission reliability in California. The Cal-ISO has outstanding payment obligations to Bonneville for such purchases. Bonneville also has a long-term seasonal power exchange agreement with SCE. Bonneville estimates that its total exposure for sales and exchanges with the foregoing California parties arising since October 1, 2000, is about $84 million. Based on its current evaluation, Bonneville recorded provisions for uncollectible amounts, which in management's best estimate are sufficient to cover any potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

In connection with the historically high power prices and volatility in West Coast power markets, FERC initiated three proceedings to address, under the Federal Power Act, whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. Bonneville is participating in the three proceedings.

In the first proceeding (the "California Refund Docket"), FERC reviewed the extent to which the prices of power sales through the Cal-PX and to the Cal-ISO were "unjust and unreasonable" in the period October 2, 2000 to June 19, 2001. FERC concluded that unjust and unreasonable pricing in fact occurred during that period. Subsequently, FERC appointed an administrative law judge to determine a pricing structure that approximates a competitive market and to determine the amount of refund liability of various power sellers that participated in such sales. Bonneville was a net seller through the Cal-PX and to the Cal-ISO during the period at issue.

In December 2002, the judge issued certain Proposed Findings that indicate the possible range of refund liability in the California Refund Docket. The Proposed Findings are subject to review by FERC. In March 2003, FERC issued an order in the California Refund Docket increasing the potential refund liability of participants, including Bonneville, to the proceeding. The increase is due to the substitution of producing area natural gas prices in place of the California gas index prices previously used in the calculation. Bonneville estimates that this could increase Bonneville's refund exposure, although the actual refund exposure to Bonneville remains uncertain. On June 25, 2003, FERC issued a ruling requiring participants (including Bonneville) in the California Refund Docket to justify their bids into the Cal-ISO and Cal-PX if such bids exceeded $250 per megawatt hour for the period January 2000 to June 2001. In view of the foregoing developments in the California Refund Docket, Bonneville expects that its aggregate refund exposure will be less than the amount owed to Bonneville by the Cal-ISO and Cal-PX and that such amounts will be netted. Nevertheless, Bonneville cannot assure that its refund exposure, if any, would be netted against amounts owed to it by the Cal-ISO and Cal-PX.

In a second proceeding (the "Northwest Spot Market Docket"), FERC reviewed the extent to which the pricing of power sales in the bilateral "spot market" in the Pacific Northwest was "unjust and unreasonable" in the period December 25, 2000 through June 19, 2001.

In calendar year 2001, a FERC-appointed administrative law judge for the Northwest Spot Market Docket made recommendations to FERC concluding, among other things, that the prices charged in the bilateral "spot market" in the Pacific Northwest during the relevant period were not unjust and unreasonable, that refunds should not be ordered, and that FERC should conduct no further hearings and should terminate the proceeding. In addition, the judge found that the reasoning that underlies the assertion of FERC's refund authority over power sales from Bonneville and other non-jurisdictional utilities to the Cal-ISO and through the Cal-PX markets in the first proceeding does not apply to bilateral power sales of such utilities in the Pacific Northwest. Parties filed petitions for rehearing and FERC issued an order on November 11, 2003, denying the petitions and affirming the judge's recommendations. Appeals challenging the order have been filed in the Ninth Circuit Court.

While Bonneville was a participant in the two foregoing refund proceedings, Bonneville took the position before FERC in certain petitions for rehearing that, under the Federal Power Act, FERC has no jurisdiction over Bonneville in the refund proceedings, and therefore that FERC may not assess refund liability against Bonneville. Several other non-jurisdictional utilities have also filed petitions for rehearing challenging FERC's assertion of jurisdiction over them in this matter. On December 19, 2001, FERC rejected Bonneville's and the other non-jurisdictional utilities' petitions. Several non-jurisdictional utilities, including Bonneville, have filed appeals in Federal appellate court.

In the third related proceeding (the "Show Cause Proceeding"), FERC announced in February 2002, that it was investigating whether any entity, including Bonneville, manipulated short-term electric power and natural gas prices in the West or otherwise exercised undue influence over wholesale prices in the West, from the period January 1, 2000 forward.

On June 25, 2003, FERC issued Show Cause Orders to over 60 Identified Entities in the Cal-ISO and Cal-PX markets. The Show Cause Orders require such entities to show why certain market activities did not constitute gaming practices. Bonneville was named as an Identified Entity. After entering into discussions with Bonneville over the allegations contained in the Show Cause Order, FERC staff has moved FERC to dismiss the matter against Bonneville. On January 22, 2004, FERC upheld the dismissal of the Show Cause order issued on June 25, 2003. Certain parties filed for rehearing of the matter and FERC denied the rehearing request. The parties appealed the matter to Federal appellate court and FERC has moved to dismiss the appeal. The Federal appellate court has not yet rendered a decision on the motion to dismiss the appeal.

Certain Statutes and Other Matters Affecting Bonneville's Power Business Line

Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region

The Northwest Power Act requires Bonneville to meet certain firm loads in the Region placed on Bonneville by contract by various Preference Customers and Regional IOUs. Bonneville does not have a statutory obligation to meet all firm loads within the Region or to enter into contracts to sell any power directly to a DSI after fiscal year 2001.

Under the Northwest Power Act, when requested, Bonneville must offer to sell to each eligible utility, which includes Preference Customers and Regional IOUs, sufficient power to meet that portion of the utility's Regional firm power loads that it requests Bonneville to meet. The extent of Bonneville's obligation to meet the firm loads of a requesting utility is determined by the amount by which the utility's firm power loads exceed (1) the capability of the utility's firm peaking capacity and energy resources used in operating year 1979 to serve its own loads; and (2) such other resources as the utility determines, pursuant to its power sales contract with Bonneville, will be used to serve the utility's firm loads in the Region. If Bonneville has or expects to have inadequate power to meet all of its contractual obligations to its customers, certain statutory and contractual provisions allow for the allocation of available power. With respect to Bonneville's proposal to manage its statutory duty to meet certain load requirements in the five-year period after fiscal year 2006, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Marketing After Fiscal Year 2006."

As required by law, Bonneville's power sales contracts with Regional utilities contain provisions that require prior notice by the utility before it may use, or discontinue using, a generating resource to serve such utility's own firm loads in the Region. The amount of notice required depends on whether Bonneville has a firm power surplus and whether the Regional utility's generating resource is being added to serve or withdrawn from serving the utility's own firm load. These provisions are designed to give Bonneville advance notice of the need to obtain additional resources or take other steps to meet such load.

Some of Bonneville's Preference Customers and all of its Regional IOU customers have generating resources, which they may use to meet their firm loads in the Region. Under requirements power sales contracts that expired in fiscal year 2001, each of these customers had to identify annually the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are also included in all Subscription Agreements under which Bonneville has a load following obligation. In connection with its Subscription Strategy, Bonneville tendered proposed requirements power sales contracts to each of the Regional IOUs for specified periods following the expiration of the IOUs' requirements contracts at the end of fiscal year 2001. All of the Regional IOUs elected not to execute such agreements.

Although Bonneville has contracts to sell firm power to extra-Regional customers, Bonneville is not required by law to offer contracts to meet these customers' firm loads. Similarly, Bonneville provides firm power to certain federal agencies within the Region; however, Bonneville is not required by law to offer to meet these agencies' firm loads.

<u>Federal System Load/Resource Balance</u>. In order to determine whether Bonneville will have to obtain additional electric power resources on a planning basis, and to determine the amount of firm power that Bonneville may have to market apart from committed loads, Bonneville periodically estimates the amount of load that it will be required to meet under its contracts.

Bonneville's loads and resources are subject to a number of uncertainties over the coming years. Among these uncertainties are: (i) the level of loads and types of loads placed on Bonneville in the Subscription contract and power rate development process; (ii) the amount of Augmentation Purchases that Bonneville will have to make to meet Subscription loads; (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions; (iv) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional loads; (v) changes in the regulation of power markets at the wholesale and retail level; and (vi) the overall load growth from population changes and economic activity within the Region. For a description of loads and resources see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION."

<u>Bonneville's Authority to Add Resources</u>. In order to meet the foregoing power sales obligations, Bonneville may have to obtain electric power from sources in addition to the existing Federal System hydroelectric projects and existing non-Federally owned generating projects, the output of which Bonneville has acquired by contract. By law, Bonneville may not own or construct generating facilities. However, the Northwest Power Act authorizes Bonneville to acquire resources to serve firm loads pursuant to certain procedures and standards set forth in the Northwest Power Act. "Resources" are defined in the Northwest Power Act to mean: (1) electric power, including the actual or planned

electric power capability of generating facilities; or (2) the actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from conservation measures. "Conservation" is defined in the Northwest Power Act to mean measures to reduce electric power consumption as a result of increased efficiency of energy use, production or distribution.

Bonneville's statutory responsibility to meet its firm power contractual obligations may lead Bonneville to acquire additional power and conservation resources. The extent to which Bonneville does so will depend on the effects of the competitive wholesale electric power market, load growth and other factors.

The acquisition of resources under the standards and procedures of the Northwest Power Act, however, is not the sole method by which Bonneville may meet its power requirements. Other methods are available. These include, but are not limited to: (1) exchange of surplus Bonneville peaking capacity for firm energy; (2) receipt of additional power from improvements at federally and non-federally owned generating facilities; and (3) purchase of power under the Transmission System Act for periods of less than five years.

Bonneville's resource acquisitions under the Northwest Power Act are guided by a Regional conservation and electric power plan (the "Power Plan") prepared by the Pacific Northwest Power and Conservation Council (the "Council"). The governors of the states of Washington, Oregon, Montana and Idaho each appoint two members to the Council, which is charged under the Northwest Power Act with developing and periodically amending a long range power plan to help guide energy and conservation development in the Region. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations. The Council also develops and periodically amends a fish and wildlife program for the Region. See "Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife."

Bonneville's Resource Strategies. Increased competition, deregulation in the electric power market and loss of hydropower flexibility due to Endangered Species Act ("ESA") constraints have major implications for Bonneville's resource acquisition strategy. Given uncertainties over the amount of loads that Bonneville will be required to meet in the long term, any resource investment that involves irrevocable, high fixed costs over a period longer than Bonneville's contracted load obligation is much riskier than it would have been in the past. Bonneville has indicated to Regional interests that Bonneville would prefer in the future to avoid assuming the responsibility of meeting incremental Regional power loads above the generating capability of the existing generating resources of the Federal System. Bonneville has also indicated that it would consider using tiered power rates under which the anticipated higher cost of electric power from new power purchases to meet such incremental loads would be recovered from customers to the extent they place incremental load obligations on Bonneville. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Marketing After Fiscal Year 2006."

Should Bonneville assume incremental load obligations above the existing generating resources of the Federal System, Bonneville believes that, in general, new resources should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available and should have costs that can be offset when hydroelectric power is available. Therefore, Bonneville's current resource strategy, in general, is to acquire resources that can accommodate yearly fluctuations in Bonneville loads and that add flexibility to the system.

Short-term (less than five year) purchases are the only type of resource that meets this resource acquisition strategy. Short-term purchases almost always will fit these conditions better than other resources, including long-term combustion turbine resources, because purchases generally do not involve incurring high, long-term fixed costs.

One risk associated with a short-term purchase strategy is the potential for high spot market prices. In general, spot market prices are high when energy demand is strong and coal and natural gas prices are high, although such prices can also rise in dry years when there is comparatively little hydroelectric power available. Since Bonneville's resources are predominantly hydro-based while most other West Coast producers are natural gas-based, Bonneville in general is at a competitive advantage when coal and gas prices are high.

A short-term purchase strategy can lead to fluctuating revenues and/or revenue requirements. In dry years, Bonneville's revenue requirements could increase as it could be forced to spend a significant amount of money for short-term purchases to meet loads, to the extent that Bonneville had loads for which Bonneville had not previously purchased power. In wet years, purchase requirements can be significantly reduced as Bonneville would meet more of its load with non-firm hydroelectric power.

By contrast to a reliance on long-term resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville will over-commit to long-term purchases and be forced to sell consequent surpluses at low prices in the market. Nonetheless, it is still possible, even with a short-term purchase strategy, that Bonneville could purchase more energy than needed and have to sell consequent surpluses at low prices. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation.

Bonneville's short-term resource purchase strategy is complemented by two other opportunities. First, Bonneville seeks to acquire power from renewable resources. The bulk of such purchases is likely to be from wind generation because of the increasing cost-effectiveness of wind generation projects and the expectation that the new wind generation projects can become operational within 12-18 months of a decision to proceed. The amount of wind energy resources that Bonneville ultimately acquires is uncertain and will depend on its future long-term Regional load obligations and the outcome of studies in progress that will assess, among other things, the impact of such an intermittent resource on power system operations. If there is a significant adverse impact, then wind purchases may be limited to a far lesser amount. With regard to renewable resources, Bonneville presently purchases a total of approximately 14.5 average megawatts from three wind energy projects in Wyoming, 20 average megawatts from two wind energy projects in central Oregon, and 30 average megawatts from a wind energy project on the eastern portion of the border between Oregon and Washington, 15 kilowatts from a solar photovoltaic project in southern Oregon, and 38 kilowatts from a solar photovoltaic project located on the Hanford Nuclear Reservation in Washington. These facilities are in operation. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project under construction in northern California. The geothermal project was originally scheduled to become operational in December 2005 but construction is behind schedule. Bonneville's power purchase contract with the geothermal developer contains provisions allowing Bonneville to terminate if certain deadlines are not achieved and it is possible that Bonneville may seek to terminate the agreement.

As a second short-term resource strategy, Bonneville encourages electric power conservation measures. Bonneville provides a $.50per megawatt-hour rate discount to those of its customers that implement conservation measures and/or renewable resource projects. In addition, Bonneville is purchasing about 100 average megawatts of electric power conservation through fiscal year 2006 as part of its conservation-augmentation strategy. Any such resource development should lessen Bonneville's reliance on spot market power purchases.

Bonneville believes that this resource strategy over the long-term is stable and is the most cost-effective strategy today given resource lead times, product demand uncertainty, and hydro system variability. In addition, the duration of Bonneville's recently executed Subscription power sales agreements, which have terms of five and ten years, means that Bonneville is not necessarily assured that it will have long-term committed loads to support higher incremental cost, long-term capital investments in resources having expected useful lives of 15 to 20 years or more. Relying on short-term purchases for the time being does not necessarily preclude other resource acquisitions, if needed, sometime in the future.

Under the Subscription Strategy, Bonneville substantially increased its contracted load obligation, which led Bonneville to make Augmentation Purchases. Consistent with the foregoing resource strategy, Bonneville has relied primarily on short-term (five years or less) purchase agreements to meld with firm power and seasonal surplus energy from the Federal System to meet these additional firm loads. See "—Power Marketing in the Period After Fiscal Year 2001."

Residential Exchange Program

The Northwest Power Act created the Residential Exchange Program to extend the benefits of low-cost federal power to all residential and small farm power users in the Region. In effect, the program has resulted in cash payments by Bonneville to exchanging utilities, who are required to pass the benefit of the cash payments through in their entirety to eligible residential and small farm customers.

Under the Residential Exchange Program, Bonneville is to "purchase power" offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology limiting the costs that may be included in an exchanging utility's average system cost to the production and transmission costs that an exchanging utility incurs for power. Bonneville is then to offer an identical amount of power for "sale" to the utility for the purpose of resale to the exchanging utility's residential users. In reality, no power would change hands. Bonneville would make cash payments to the exchanging utility in an amount determined by multiplying the exchanging utility's eligible residential load times the difference between the exchanging utility's average system cost and Bonneville's applicable PF rate, if such PF rate is lower. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates." The net costs of the Residential Exchange Program are shown in the Federal System Statement of Revenues and Expenses set forth under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data."

As part of the Subscription Strategy, Bonneville signed agreements with the Regional IOUs to settle Bonneville's Residential Exchange obligation for the period July 1, 2001 through September 30, 2011. These agreements provide for both sales of power and cash payments to the Regional IOUs. Bonneville's settlement of its Residential Exchange obligations was later challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program (the "Council Program"). In addition, in the wake of certain listings of fish species under the ESA as threatened or endangered, Bonneville is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the National Oceanographic and Atmospheric Administration—Fisheries ("NOAA Fisheries," which is a part of the U.S. Department of Commerce and which was formerly known as National Marine Fisheries Service) and the U.S. Department of Interior acting through the U.S. Fish and Wildlife Service ("Fish and Wildlife Service") in furtherance of the ESA.

Bonneville typically funds fish and wildlife mitigation through several mechanisms. Since the creation of the Federal System, Bonneville has repaid the United States Treasury the share of the costs of mitigation by the Corps and the Bureau that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the federal projects' power purpose (as opposed to other project purposes such as irrigation, navigation and flood control). These measures mitigate for the impact on fish and wildlife of the construction and operation of hydroelectric dams of the Federal System.

Bonneville also implements and funds measures proposed in the Council Program, which the Council periodically amends. The Council Program calls for a variety of mitigation measures from habitat protection to mainstem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and force Bonneville to purchase power to fulfill contractual demands or to spill water and thereby forgo generation of electricity, for instance, those financial losses are counted as measures funded by Bonneville. While many of the measures in the Council's Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's Program measures, especially those designed to benefit species not listed under the ESA, are in addition to ESA-directed measures. See "—Council's Fish and Wildlife Program."

Bonneville's fish and wildlife costs fall into two main categories, "Direct Costs" and "Operational Impacts," both of which are driven primarily by ESA requirements. Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing the Council Program, and which include expense and capital components for ESA–related and some non-ESA-related measures that are located at sites away from the Federal System dams; (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps, Bureau and Bonneville; and, (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for the Lower Snake River Hatcheries and of the Corps and Bureau for Federal System projects.

"Operational Impacts" include "Replacement Power Purchase Costs" and "Foregone Power Revenues." Replacement Power Purchase Costs are the costs of certain power purchases made by Bonneville that are attributable to river operations in aid of fish and wildlife. To determine these costs in a given year, Bonneville compares the actual hydroelectric generation in such year against the hydroelectric generation that would have been produced had the hydroelectric system been operated without any fish and wildlife operating constraints. To the extent that this comparison indicates that Bonneville made a power purchase to meet load, which purchase Bonneville would not have had to make had the river been operated free of fish constraints, Bonneville accounts for such value as a fish and wildlife cost. "Foregone Power Revenues," are revenues that would have been earned absent changes in hydroelectric system operations attributable to fish and wildlife.

Bonneville estimates that in aggregate, Direct Costs and Replacement Power Purchase Costs were about $479.3 million in fiscal year 2004. In addition, Bonneville estimates that it had about $21.7 million in Foregone Power Revenues.

The Endangered Species Act. As noted above, Bonneville, the Corps and the Bureau are subject to the ESA. To a great extent, compliance with the ESA determines how the Federal System is operated for fish and dominates most fish and wildlife planning and activities. The listings have resulted in major changes in the operation of the Federal System hydroelectric projects and a substantial loss of flexibility to operate the Federal System for power generation. Apart from changes in Federal System operations that adversely affect power generation, compliance with the ESA has also resulted in additional Federal System costs in the form of non-operational measures funded from Bonneville revenues.

Among other things, the ESA requires that federal agencies such as Bonneville, the Corps and the Bureau, take no action that would jeopardize the continued existence of listed species or result in the destruction or adverse modification of their critical habitat. Since 1991, there have been listed as threatened or endangered under the ESA 12 species of anadromous fish (salmon and steelhead) that are affected by operation of the Federal System. It is possible that other species may be listed or proposed for listing in the future. In general, the effect of the listing of the fish species under the ESA, and certain other operating requirements resulting from Bonneville's fish and wildlife obligations under the Northwest Power Act, is that, except in emergencies, the Federal System is now operated for power production after meeting needs for flood control and the protection of ESA-listed fish.

In connection with the listing of these species, NOAA Fisheries has prepared certain biological opinions addressing the listed species. The biological opinions provide information that Bonneville, the Corps and the Bureau can use to ensure that their actions with respect to the operation of the Federal System satisfy the ESA. By acting consistently with the biological opinions, Bonneville, the Corps and the Bureau generally demonstrate that jeopardy to listed species is being avoided. Specifically, Bonneville, the Corps and the Bureau have chosen to implement certain specified measures recommended in the biological opinions as being necessary to avoid jeopardy. The adequacy of the biological opinions and their implementation are subject to, and have been subjected to, judicial review.

Operation of the Federal System consistent with the biological opinions has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise be run through turbines to generate electricity may be spilled to aid in downstream fish migration without producing electric energy. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration.

Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these changes, under certain water conditions, Bonneville has had to, and may have to, purchase additional energy for the fall and winter to meet load commitments than would otherwise have been met with the hydroelectric system. In addition, the flow changes have meant that Bonneville has had comparatively more surplus energy to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System in conformance with the biological opinions and the Council Program, as in effect as of the beginning of fiscal year 2000, decreased Federal System generation capability by about 1000 average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the first biological opinion in 1995. The consequences of this decrement in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

While in calendar years 1999-2001 the seasonal variance in market prices of electric power was substantially less pronounced, historically, power prices in the Northwest have been much higher in the winter because of higher Regional heating requirements and lower in the spring and summer as those requirements abated. Thus, flows in aid of fish have resulted in a reduction in the amount of power generally, and reduced the amount of power in high winter load portions of the year when power has typically had greater economic value.

These ESA listings and related actions to protect listed species and their habitat have also resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville fish costs increased from about $20 million in fiscal year 1981 to $150 million in fiscal year 1991. After the issuance of the first biological opinion affecting Federal System operations, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in 1995. As noted above, Bonneville estimates that the total of Direct Costs and Operational Impacts in fiscal year 2003 was about $518.8 million and about $501 million in fiscal year 2004.

2000 and 2004 Biological Opinions. In December 2000, NOAA Fisheries promulgated a biological opinion ("2000 Biological Opinion") that superseded all previous opinions issued by it concerning the Federal System hydroelectric dams. The 2000 Biological Opinion was coordinated with a Fish and Wildlife Service biological opinion issued in 2000 relating to certain other species and they are intended to be mutually consistent. The 2000 Biological Opinion included a number of measures affecting Federal System dam operations and dam configurations in order to improve anadromous fish passage survival through the hydro system.

Included among the 13 biological opinion alternatives around which Bonneville developed its 2002 Final Power Rates were several that would have called for breaching four Federal System Snake River dams. The direct cost of breaching the dams would be very high. In addition, the loss of the generation from the dams would substantially affect the power generation capability of the Federal System, reducing current expected output by approximately 1200 average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales.

A number of interests filed litigation in connection with the 2000 Biological Opinion. In May 2003, the United States District Court for the District of Oregon ruled that the 2000 Biological Opinion is inadequate because it relied on offsite mitigation measures that were "not reasonably certain to occur." In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. On November 30, 2004, NOAA Fisheries finalized a new biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court.

The 2004 Biological Opinion calls for multi-million dollar improvements in fish passage facilities at federal dams on the Snake and Columbia rivers over the next ten years. In addition, the 2004 Biological Opinion calls for enhanced efforts to reduce predation on juvenile salmon, improvements in downstream transportation of migrating salmon, and changes in fish hatchery operations. Federal agencies, including Bonneville, the Corps and the Bureau, estimate a total spending commitment of over $6 billion over the planned ten-year life of the 2004 Biological Opinion. This amount is roughly equivalent to forecasted spending under the 2000 Biological Opinion. As with the 2000 Biological Opinion, the 2004 Biological opinion does not recommend implementation of dam breaching. In the opinion of the General Counsel to Bonneville, legislation by Congress would be required in order for the breaching of the dams to be authorized. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

The adoption by NOAA Fisheries of the 2004 Biological Opinion has prompted additional litigation based on alleged violations of the ESA. Bonneville is unable to predict the manner in which or likelihood that such litigation will affect the 2004 Biological Opinion. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the Office of Management and Budget, DOE and other agencies agreed to provide for certain federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision allows Bonneville to exercise its Northwest Power Act authorities to implement fish and wildlife mitigation on behalf of all of a project's Congressionally authorized purposes, such as irrigation, navigation, power and flood control, then recoup (*i.e*., take a credit for) the portion allocated to non-power purposes. The agreement also directs Bonneville to recoup certain Direct Costs and Replacement Power Purchase Costs. The amount of such recoupments was about $354 million, $38 million, $97 million, and $77 million in fiscal years 2001, 2002, 2003, and 2004, respectively. These credits are treated as revenues in Bonneville's ratemaking process, and such recoupments are taken against Bonneville's lowest priority financial obligation, its payments to the United States Treasury. The recoupments are initially taken based on estimates and are subsequently modified to reflect actual data. Two important costs that may be recouped under section 4(h)(10)(C) are the cost of foregone power revenues and replacement power purchases arising from certain hydroelectric system operations for the benefit of fish and wildlife. Both of these categories of costs can occur to a greater degree in dry years when, historically, market prices for power are comparatively high. Thus, Bonneville believes that the amount of 4(h)(10)(C) recoupments will tend to be greater in dry years when power prices tend to be high and Bonneville has less power to market, and therefore tends to have lower power revenues.

Council's Fish and Wildlife Program. In November 2002, the Council adopted a new Fish and Wildlife Program (the "2002 Program"). The 2002 Program focuses on an ecosystem approach to rebuilding fish and wildlife populations in the Columbia River Basin, consistent with the 2000 Biological Opinion. Estimated costs to Bonneville of the Council's measures, as then encompassed in amendments to the Council's 1995 Program, were included in Bonneville's assumptions for the 2002 Final Power Rates. The 2002 Program, like the Council's predecessor program, sets forth an "integrated program" budget to Bonneville for both the Council Fish and Wildlife Program and the off-site mitigation program under the 2000 Biological Opinion. The costs of the integrated program ("Integrated Program Costs") are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General." The 2002 Program has not yet been updated to reflect the 2004 Biological Opinion.

In response to financial developments, Bonneville reiterated, and the Council confirmed, an average expense accrual budget level of $139 million per year for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's 2002 Program for fiscal years 2003 through 2006. This level is in the range of projected costs assumed in

Bonneville's 2002 Final Power Rates. In June 2003, the Yakama Nation, a tribal entity, filed a petition in the Ninth Circuit Court to request a review of Bonneville's fund levels under the Council's 2002 Program, as well as the Council's support of such funding levels. See "BONNEVILLE LITIGATION—Yakama Nation Litigation."

Bonneville can provide no assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System, including measures resulting from current and future listings under the ESA, current and future biological opinions or amendments thereto, future Council Fish and Wildlife Programs or amendments thereto, or litigation relating to the foregoing.

Power Marketing in the Period After Fiscal Year 2001

General. Under a power marketing approach (the "Subscription Strategy") begun in 1997, Bonneville proposed to subscribe access to Federal System electric power under long-term contracts to its Regional customers for the period after October 1, 2001, which is the date after which virtually all of Bonneville's prior Regional power sales contracts and all of Bonneville's Residential Exchange Program Contracts expired. Under the Subscription Strategy, Bonneville entered into long-term Subscription contracts through which it contracted to sell all of its then available firm power to Regional customers for various terms.

Preference Customer Loads. Under the Subscription Strategy, Bonneville entered into long-term power sales contracts directly or indirectly to provide power to meet loads of about 135 Preference Customers. With the exception of eight contracts having terms of five years and representing about 800 average megawatts of load, such agreements have terms of ten years.

Under the Subscription Strategy, Bonneville sells Preference Customers three basic power products, which are not exclusive of each other: (i) Block Sales under which Bonneville provides ten-year fixed blocks of power at agreed times on a take or pay basis, (ii) Slice of the System, a form of requirements service in which Bonneville sells a proportion of Federal System output (including both firm power and what would otherwise be seasonal surplus energy) in return for a promise of the customer to pay a correlative proportion of the costs of the Federal System, and (iii) Partial and Full Requirements Products under which Bonneville provides partial or full requirements service for all or a portion of a customer's loads. Full requirements customers accept constraints on their ability to shape their purchases from Bonneville for any reason other than following variations in consumer load. Partial requirements service is made available to Preference Customers who request firm power load requirements service but who also want some flexibility to shape their purchases from Bonneville to optimize their own resource operations.

Under the foregoing agreements Bonneville is obligated to provide roughly 6300-6400 average megawatts to meet Preference Customer loads, on average, over the remaining term of the five-year rate period beginning October 1, 2001. Of this amount, about 1600 average megawatts is sold as Slice of the System, about 1900 average megawatts is in the form of Block Sales and the remainder is in the form of Requirements Products. The actual amount of power sold by Bonneville under the Slice of the System contracts varies from year to year depending on actual generation. The 1600 average megawatts figure reflects the firm power component of the Slice of the System. Slice of the System customers also receive what otherwise would be seasonal surplus energy in amounts that depend on precipitation in the Columbia River drainage. A Regional IOU has challenged Bonneville's statutory authority to enter into Slice of the System contracts. See "BONNEVILLE LITIGATION—Pacific Northwest Generating Cooperative v. Bonneville Power Administration."

The exact amount of Bonneville's obligation to Preference Customers is somewhat uncertain and depends on conservation activities, actual demand (which can fluctuate with weather and Regional economic activity), load reduction arrangements and other factors. For example, Bonneville entered into certain agreements with Preference Customers to reduce loads placed on Bonneville in fiscal years 2002 and 2003.

The Slice of the System (or "Slice") contracts require that customers make monthly payments based on forecasted costs of the Federal System, with specific exceptions. These monthly payments are subject to an annual "true up" adjustment for actual costs. The Slice customers have the right to have an outside auditing firm conduct an audit of such annual "true up" adjustments and costs. Certain Slice customers requested such an audit of the fiscal year 2002 "true up" adjustment and costs, and retained an accounting firm to conduct an audit and prepare a final report, which was completed on June 13, 2003. The Slice customer audit asserted that the Slice customers' payments for fiscal year 2002 should be adjusted by removing $83 million from Bonneville's charges. Bonneville issued a 'Response to the Final Slice Audit Report' ("Response") and rejected some of the adjustments. Some of Bonneville's non-Slice customers have filed litigation with the Ninth Circuit Court challenging Bonneville's Response. Currently, Bonneville, the non-Slice customer litigants and the Slice customers are in settlement mediation discussions on the matter. Bonneville made about $31 million in "true up" payments to Slice customers with respect to fiscal year 2003 and Slice customers did not conduct an audit. Slice customers made about $10 million in "true up" payments to Bonneville with respect to fiscal year 2004. The Slice Customers have asked for an audit of the fiscal year 2004 Slice "true up" adjustment and costs. Depending on the result of the mediation or alternatively the litigation, pertaining to the true-up payments for fiscal year 2002, it is possible that the true-up payments with respect to fiscal years 2003 and 2004 could also be adjusted. See "BONNEVILLE LITIGATION—Slice Litigation."

Residential Exchange Program Obligations. As part of the Subscription Strategy, Bonneville and the six Regional IOUs participating in the Residential Exchange Program entered into six separate ten-year contracts ("Residential Exchange Settlement Agreements") that settle Bonneville's statutory Residential Exchange Program obligations during such periods. For the five years beginning October 1, 2001, Bonneville originally contracted to satisfy this obligation through (i) direct sales of 1000 average megawatts of firm power at Bonneville's Residential Load Rate ("RL Rate") and a similar rate in the case of a comparatively small Regional IOU, and (ii) cash payments for an exchange value ("Monetary Benefits" as described immediately below) of 900 average megawatts of firm power. The RL Rate is set at a level equivalent to Bonneville's lowest available requirements service rate, the PF Rate. The "Monetary Benefits" are based on the related amount of power multiplied by the difference between a forecast of the market price of power set in Bonneville's rate case and the RL Rate. All power sales and payments by Bonneville under the Residential Exchange Settlement Agreements, as amended, are provided for the benefit of the Regional IOUs' residential and small farm loads in the Region.

Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of contract amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2001. These amendments and arrangements increased the amount of cash payments that Bonneville would make in respect of the Residential Exchange Settlement Agreements and reduced the amount of physical power sales thereunder. As result, the aggregate cash payments to Regional IOUs that Bonneville has made related to the Residential Exchange Settlement Agreements were about $355 million in fiscal year 2002, $327 million in fiscal year 2003 and $388 million in fiscal year 2004. Under a variety of assumptions, such payments are projected to be about $387 million in fiscal year 2005, and $382 million in fiscal year 2006. As a result of the foregoing load reductions, Bonneville reduced its obligation to make physical power sales under the Residential Exchange Settlement Agreements to 258 average megawatts of power from fiscal year 2002 through fiscal year 2006. This remaining Residential Exchange Settlement Agreement power sale is to a single Regional IOU (Portland General) at the RL Rate, and is subject to the LB-CRAC, FB-CRAC and SN-CRAC rate level adjustments. The above power sale to Portland General for fiscal years 2003 through 2006 has an assumed benefit (market value of power minus power purchase costs) to PGE of roughly $25 million per year.

The aggregate cash payments to Regional IOUs described above can be broken down into three main components. The first component reflects payments for Monetary Benefits under the original Residential Exchange Settlement Agreements. Monetary Benefits paid by Bonneville were approximately $143 million in each of fiscal years 2002 and 2003 and $128 million in fiscal year 2004. Projected Monetary Benefits to be paid by Bonneville are $143 million and $137 million in fiscal years 2005 and 2006, respectively.

The second component is the reflection of certain agreements by Regional IOUS to defer payments from Bonneville relating to the Residential Exchange. These deferrals reshaped the payments by Bonneville within the current five-year rate period. The deferrals resulted in a reduction in payments to the Regional IOUs in fiscal years 2002 and 2003 and comparably increased payments in 2004. Payment by Bonneville of the deferred amount was about $33 million in fiscal year 2004.

The third component reflects payments for load reductions arising from contract amendments and certain other arrangements wherein Regional IOUs converted their rights to receive low cost power from Bonneville into rights to obtain cash payments from Bonneville. Certain of these payments are subject to further adjustment if there is a settlement of certain litigation filed by Preference Customers challenging Bonneville's authority to enter into the Residential Exchange Settlement Agreements. In June 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements that reduce by one half certain payments in the aggregate amount of $200 million that Bonneville otherwise owed to the two subject Regional IOUs in fiscal years 2005 and 2006 under their Residential Exchange Settlement Agreements. In addition to the foregoing reduction in payments, Bonneville and such Regional IOUs agreed that Bonneville could defer paying until fiscal years 2007-2011 the remaining $100 million aggregate amount (plus interest) otherwise owed by Bonneville to the two Regional IOUs in fiscal years 2005 and 2006. In return, the two Regional IOUs obtained assurances from Bonneville as to the amount and nature of Residential Exchange Settlement benefits to be provided to them by Bonneville in fiscal years 2007-2011, as described below.

With respect to the other four Regional IOUs, Bonneville has also entered into agreements having terms similar to those for Puget and PacifiCorp, although the reduction in financial payments that Bonneville will make to such

Regional IOUs in the current rate period will be only $3-$4 million in aggregate. Taking into account the initial load reduction payment obligations, the contract conversions to monetary payments and the effects of the foregoing litigation discounts, Bonneville made payments to Regional IOUs in respect of the load reductions and conversions in the amount of $227 million in aggregate in fiscal year 2004 and expects to make similar payments thereto in the aggregate amount of $244 million in fiscal year 2005 and $236 million in fiscal year 2006.

The foregoing payments to and by Bonneville under the Residential Exchange Settlement Agreements are affected by the application of at least one of the three intra-rate period rate level adjustments included in the 2002 Final Power Rates. For example, the remaining Subscription power sale by Bonneville and the three converted power sales are served under the RL Rate and are therefore subject to the LB-CRAC, FB-CRAC and SN-CRAC. The payments by Bonneville to Puget and PacifiCorp under the load reduction amendments are reduced when Bonneville employs a rate level adjustment under the SN-CRAC. In addition, since the Monetary Benefits are subject to certain changes by reference to the RL Rate, Bonneville's Monetary Benefits payments are reduced when the RL Rate level is increased under the SN-CRAC. See "—Subscription Power Rates."

In developing the Subscription process, Bonneville originally expected to meet its Residential Exchange Settlement Agreement obligations in the period after fiscal year 2006 in full through the actual provision of about 2200 average megawatts of electric power to the Regional IOUs.

As a result of certain agreements, Bonneville will provide and the Regional IOUs will receive only Monetary Benefits and not physical power under the Residential Exchange Settlement Agreements in fiscal years 2007-2011, thereby reducing Bonneville's load uncertainty by roughly 2200 average megawatts in each of the five fiscal years. The aggregate financial benefits paid by Bonneville in fiscal years 2007-2011 will have a floor of $100 million per fiscal year and a maximum of $300 million per fiscal year, although Bonneville will also pay the deferred amount of $100 million plus interest to Puget and PacifiCorp referred to above. In addition, Bonneville and the Regional IOUs have agreed to an independent market price indicator for determining Monetary Benefits in such period, rather than the use of market price indicators developed by Bonneville in its power rate cases.

The Residential Exchange Settlement Agreements and the subsequent agreements between Bonneville and the related Regional IOUs relating thereto have been challenged in court by other Bonneville customers. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

<u>DSI Loads</u>. Historically, Bonneville sold substantial amounts of Federal System electric power to DSIs that smelt or fabricate aluminum. In 1981, as directed by the then recently enacted Northwest Power Act, Bonneville entered into 20-year power sales contracts with eligible DSIs. Under the 1981 contracts Bonneville was obligated to sell the aluminum company DSIs up to roughly 3200 average megawatts of power in aggregate. Under certain 1996 replacement agreements, the DSI loads Bonneville was obligated by contract to serve was reduced to roughly 1800 average megawatts through fiscal year 2001.

The United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court") has held that Bonneville no longer has a statutory obligation to sell any power to meet DSI loads. Nonetheless, as part of Bonneville's Subscription program for the post-fiscal year 2001 period, Bonneville entered into five-year take-or-pay power sales contracts with a number of aluminum company DSIs under which agreements such DSIs agreed to purchase approximately 1500 average megawatts in aggregate.

Notwithstanding these original Subscription contracts, Bonneville's contracted sales obligations to aluminum company DSIs in fiscal year 2005 and 2006 are about 200-300 average megawatts. The remainder of the sales to aluminum company DSIs (i) have been curtailed by contract amendment, (ii) were terminated because they were rejected in bankruptcy proceedings, or (iii) are not being performed by related DSIs pending likely rejection in bankruptcy proceedings. Currently, four aluminum company DSIs are under bankruptcy protection. See "BONNEVILLE LITIGATION—GNA Bankruptcy," "—Kaiser Aluminum Bankruptcy," and "—Longview Aluminum Bankruptcy." In view of the foregoing bankruptcies and continued low prices for aluminum relative to the costs of production, and in particular the current and expected price of electric power in the Western United States, Bonneville's expectation is that aluminum company DSI loads will remain at very low levels through at least fiscal year 2006.

<u>Subscription Strategy Contracts Opt-Out Provisions</u>. While Bonneville and its customers have entered into the foregoing Subscription contracts, the ultimate amount of electric power load Bonneville is and will become obligated to meet under such contracts through fiscal year 2011 remains somewhat uncertain because, among other reasons, the Subscription contracts have provisions allowing customers to terminate such contracts if either FERC or the Ninth Circuit Court, which reviews FERC actions on Bonneville's rates, subsequently remands Bonneville's base power rates and Bonneville publishes a record of decision that adopts different rates for such period. The customers

may not opt out of their contracts solely on the basis that Bonneville has included the cost recovery adjustment clauses in the rate proposal or that the cost recovery adjustment clauses are employed to increase rate levels. The customers who do not opt out after review of the final rate proposal would be committed to purchase as provided in their Subscription contracts. The 2002 Final Power Rates were approved by FERC in July 2003 but are the subject of litigation in the Ninth Circuit Court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

Subscription Power Rates. On June 29, 2001, Bonneville filed its proposed 2002 Final Power Rate Proposal with FERC for the five years beginning October 1, 2001. On July 21, 2003, FERC granted final approval of such rates, although they have been challenged in litigation in the Ninth Circuit Court. The 2002 Final Power Rates include base rates applicable to the varying types of Subscription agreements and certain intra-rate period adjustments that increase or decrease power rate levels depending on certain conditions. The base rate levels are between approximately 1.9 cents per kilowatt-hour and 2.3 cents per kilowatt-hour, excluding transmission and depending on type of service. The base rates are at levels similar to those in effect for like service in the immediately preceding rate period. The 2002 Final Power Rates also include three intra-rate period adjustment mechanisms under which Bonneville can increase, and in some instances decrease, power rate levels: a Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), a Financial Based Cost Recovery Adjustment Clause ("FB-CRAC") and a Safety Net Cost Recovery Adjustment Clause ("SN-CRAC").

The LB-CRAC is designed to recover the net cost of system Augmentation Purchases and certain load reduction agreements that is over and above the cost of such purchases that Bonneville forecasted in a rate filing prepared in July 2000. The LB-CRAC is not designed to recover the cost of replacing reductions in the firm power generating capability included in the baseline estimate of Federal System firm power if any such reductions occur.

The LB-CRAC is based on periodic forecasts of Bonneville's Subscription augmentation and certain related costs for consecutive six-month periods during the five-year rate period. The costs recovered under the LB-CRAC are those identified costs to Bonneville from addressing the increased loads it assumed under its Subscription power sales agreements, and include the costs of certain power purchases and certain load reduction agreements. Thus, the LB-CRAC is revised each six-month period during the rate period to reflect updated forecasts of Subscription Augmentation Purchase and load reduction costs in the next six months. Another adjustment to the amounts recovered under LB-CRAC reflects actual costs of Subscription Augmentation Purchases in the prior six-month period to the extent that the forecast for such augmentation costs differ from actual costs in such period. The LB-CRAC is based on the costs of certain Subscription Augmentation Purchases and certain load reduction agreements only and is not subject to any other provision limiting the amount of revenues to be derived by Bonneville thereunder.

The FB-CRAC is designed to restore, on a forecasted basis, Bonneville's financial reserves to certain fiscal year-end reserve levels ("Reserve Targets"). A rate level increase under the FB-CRAC is implemented for an entire fiscal year and occurs during a subject fiscal year only if Bonneville's financial forecast made in the third quarter of the prior fiscal year indicates that the accumulated net revenues for the beginning of the subject fiscal year will be below the accumulated net revenue equivalent of the applicable Reserve Target. The FB-CRAC was designed to increase revenues up to a maximum of between $90 million and $115 million per fiscal year, depending on the year, through fiscal year 2006.

The SN-CRAC is to be implemented to recover costs on a temporary basis if, at any time during the rate period, Bonneville were to (i) forecast a 50% probability or greater of missing a scheduled payment to the United States Treasury or other creditor or (ii) miss a scheduled payment to the United States Treasury or other creditor. A rate level increase under the SN-CRAC occurs independently of any LB-CRAC or FB-CRAC increase then in effect.

Sales under Slice of the System contracts (about 1600 average megawatts of firm power plus proportionate amounts of Federal System power that would otherwise be seasonal surplus energy) are not subject to the SN-CRAC or the FB-CRAC but are subject to the LB-CRAC. These customers agreed to pay for a fixed portion of Federal System costs under their contracts and their rates are subject to annual adjustment to recover those costs. About 800 average megawatts of loads of certain small Preference Customers under requirements contracts are not subject to any of the three rate level adjustment mechanisms. These Preference Customers received certain contractual rate protections from Bonneville for making early contract commitments to purchase power from Bonneville on a long-term basis. All other Subscription power sales (Block Sales and the sale of Requirements Products) to Preference Customers are subject to all three rate adjustment mechanisms. The 1500 megawatts of Subscription power sales to DSIs are also subject to all three rate adjustments, although Bonneville expects that the DSIs are unlikely to meet their originally contracted aggregate purchase obligations to a substantial degree. The remaining 200-300 megawatts of Subscription power sales under the Residential Exchange Settlement Agreements are subject to the LB-CRAC, FB-CRAC and the SN-CRAC.

With respect to the SN-CRAC, in June 2003, Bonneville issued a final proposal and record of decision for an SN-CRAC rate level adjustment (the "2004 SN-CRAC Rate Level Adjustment"). On May 10, 2004, FERC approved the 2004 SN-CRAC Rate Level Adjustment.

The 2004 SN-CRAC Rate Level Adjustment is a variable contingent mechanism where the calculation of the actual rate level adjustment for a fiscal year is made shortly before the beginning of such fiscal year. The adjustment is based on then current forecasts of the Power Business Line accumulated net revenues for the fiscal year preceding the fiscal year in which the rate level adjustment is to be in effect. Thus, the first year (fiscal year 2004) rate level adjustment under the 2004 SN-CRAC Rate Level Adjustment was determined in August 2003 on the basis of then available financial forecasts of fiscal year end 2003 accumulated net revenues. Under that determination, Bonneville's SN-CRAC rate level adjustment applicable in fiscal year 2004 was about 10 percent. With respect to fiscal year 2005, in September 2004 Bonneville concluded that it would reduce to zero the rate level adjustment under the 2004 SN-CRAC Rate Level Adjustment.

Assuming the effects and the expected effects of the 2004 SN-CRAC Rate Level Adjustment and expected and actual rate level adjustments under the FB-CRAC and LB-CRAC, Bonneville's average power rates for fiscal years 2004-2006 are expected to exceed by more than 50 percent the rate levels in effect for like service in fiscal year 2001, the year preceding the current power rate period. As described in this Appendix A, the rate level increases under the rate adjustment mechanisms vary depending on the type of Subscription power sales contract. Some contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms. For a description of actual and projected Subscription power rate levels see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION--Subscription Strategy, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments" and the table "Bonneville Full Requirements Power Rate Levels 1996-2006."

Rates for Surplus Power. With regard to rates for surplus firm power, Bonneville continues to employ flexible rates that recover Bonneville's cost of providing such power, but at rates that enable Bonneville to participate in power markets. The amount of surplus power that Bonneville will market at such rates will depend on generation and load conditions that vary with weather, streamflows, market conditions and numerous other factors. Rates for the sale of surplus power are not subject to the rate adjustment mechanisms applicable to Subscription power sales.

Recovery of Stranded Power Function Costs

As a consequence of regulatory and economic changes in electric power markets, many utilities see potential for certain of their costs, in particular power system costs, to become unrecoverable, *i.e*., "stranded." Stranded costs may arise where power customers are able, pursuant to new open transmission access rules, to reach new sources of supply, leaving behind unamortized power system costs incurred on their behalf. Bonneville could also face this concern. While Bonneville has separate statutory authority requiring it to assure that its revenues are sufficient to recover all of its costs, additional authority may be required to assure that such costs, including Bonneville's payments to the United States Treasury, are made on time and in full. Depending on the exact nature of wholesale and retail transmission access, it is possible that Bonneville's power function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. See "—Power Marketing Plan for the Period After Fiscal Year 2001." Nonetheless, Bonneville cannot predict with certainty its cost of power or market prices.

FERC's 1996 order, "Order 888," to promote competition in wholesale power markets established standards that a public utility under the Federal Power Act must satisfy to recover stranded wholesale power costs. The standards contain limitations and restrictions, which, if applied to Bonneville, could affect Bonneville's ability to recover stranded costs in certain circumstances. However, Bonneville's General Counsel interprets FERC Order 888 as not addressing stranded cost recovery by Bonneville under either the Northwest Power Act or sections 211/212 of the Federal Power Act. For a discussion of Order 888 and sections 211/212 of the Federal Power Act, as amended by EPA-1992, see "TRANSMISSION BUSINESS LINE—Nondiscriminatory Transmission Access and Separation of Business Lines."

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211/212 of the Federal Power Act are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under sections 211/212.

Shortly after the issuance of Order 888, Bonneville requested clarification of the application of FERC's stranded cost rule to Bonneville in the context of an order for transmission service under sections 211/212. In FERC Order 888-A, modifying original FERC Order 888, FERC addressed Bonneville's request by stating: "We clarify that our review of stranded cost recovery by [Bonneville] would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate [Bonneville] . . . and/or section 212(i), as appropriate." Therefore, it remains unclear how FERC would intend to balance Bonneville's Northwest Power Act cost recovery standards with the stranded cost rule as enunciated in FERC Order 888 in the context of FERC-ordered transmission service pursuant to sections 211/212. Contrary to the opinion of Bonneville's General Counsel, several of Bonneville's transmission customers have taken the position that transmission rates may not be set to recover stranded power costs as Bonneville envisions under the Northwest Power Act. For a discussion of the proposed formation of a regional transmission organization that could affect some of Bonneville's transmission operation functions, see "TRANSMISSION BUSINESS LINE—Bonneville's Participation in a Regional Transmission Organization."

Changes in the Regulation of Regional Retail Power Markets

Since the 1990's, many states and the Federal government have examined possible regulatory changes in retail electric power markets. In general, these proposals would allow end-use electricity consumers to choose their energy suppliers and to purchase power at market prices. This approach contrasts with the formerly predominant regulatory approach, where electric utilities have legal or de facto exclusive retail service territories. In general, the utilities are under an obligation to provide service to consumers located in the utilities' respective service areas. The utilities receive regulated rates of return in the case of profit-making utilities, or are required to sell their power at rates that are cost-based in the case of public agency or cooperatively owned utilities. As under wholesale competitive power markets, the core issue in establishing retail choice is assuring that facilities for transmitting electric power, at the distribution level, be available to all market participants in a manner that does not discriminate in favor of power sales by the owner of such facilities.

Bonneville is limited in its legal authority to sell power directly to end-use consumers, other than to state and Federal agencies and specified DSIs. Accordingly, Bonneville expects to continue to sell the majority of its electric power on a wholesale basis to electric utilities who resell to retail loads. The advent of competition in retail power markets could affect the manner in which Bonneville markets power and the ability of its wholesale customers, in particular its Preference Customers, to maintain the electric power loads they now rely on Bonneville to meet. In such a scenario, Bonneville may be forced to market more of its power to non-utility marketers or load aggregators for resale to end-users. Depending on the terms of any retail access legislation, the reliability of revenues Preference Customers now have from electric power consumers could be diminished. Under some retail access approaches, utilities would have a reduced ability to recover power costs in reliance on their exclusive ownership of distribution facilities for retail service to their end-users.

TRANSMISSION BUSINESS LINE

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately- and publicly-owned utilities, power marketers, power generators and others. Bonneville's revenues from the sale of transmission and related services accounted for roughly 17 percent of Bonneville's overall revenues in fiscal year 2004.

Bonneville's Transmission Business Line provides transmission service under FERC's pro forma Open Access Transmission Tariff. Two transmission services are offered under the Tariff: Point-to-Point and Network Integration. These services are available to all customers regardless of whether they are transmitting Federal or non-Federal power. Much of Bonneville's transmission service is provided to deliver Bonneville's power sales obligations to its Preference Customers, many of whom take Network Integration service. Point-to-Point service is taken typically by marketers, independent power producers and customers that own or purchase the output of remote generating resources which must be delivered to their service territories. Finally, Bonneville, as an owner of the northern portions of the Pacific Northwest-Pacific Southwest Intertie ("Intertie") and southern portions of certain transmission lines connecting areas of western Canada with the Region, obtains transmission revenues from providing Point-to-Point service to power marketers who need Bonneville transmission service to effect power sales and related transactions inside and outside the Region.

While it is difficult to generalize as to the cost of transmission service needed to effect various power transactions, a useful point of reference may be the cost borne by certain Regional full requirements Preference Customers of Bonneville's. These customers pay roughly $3.50 to $4.00 per megawatt hour for Network Integration transmission and ancillary services to Bonneville to provide delivery of firm power that Bonneville sells at the PF rate, which is currently priced at roughly $27 to $31 per megawatt hour, depending on type of service and exclusive of transmission. Other customers, such as marketers using Point-to-Point service to transmit non-Federal power, pay approximately $2.50 to $3.00 per megawatt hour for transmission and ancillary services.

Bonneville's Transmission System

The Federal System includes the transmission system that is owned, operated and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-federal power resources. Bonneville's transmission system (also referred to as the "Federal transmission system") is composed of approximately 15,000 circuit miles of high voltage transmission lines, and over 300 substations and other related facilities that are located in Washington, Oregon, Idaho, and portions of Montana, Wyoming and northern California. The Federal transmission system includes an integrated network for service within the Pacific Northwest ("Network"), and approximately 80% of the northern portion (north of California and Nevada) of the combined Southern Intertie. The Southern Intertie consists of three high voltage Alternating Current ("AC") transmission lines and one Direct Current ("DC") transmission line and associated facilities that interconnect the electric systems of the Pacific Northwest and Pacific Southwest and provide the primary bulk transmission link between the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4800 megawatts of capacity, and in the south to north direction is 3675 MW. The rated transfer capability of the DC line in both directions is 3100 MW. The operating transfer capability (or reliability transfer capability) of these facilities varies by generation patterns, weather conditions, load conditions and system outages.

The Federal transmission system is used to deliver power between resources and loads within the Pacific Northwest, and to transmit power between and among the Region, western Canada and the Pacific Southwest. Bonneville's Transmission Business Line provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Business Line for its out-of-Region sales; entities that buy and sell non-Federal power in the Region, such as Regional IOUs, Preference Customers, extra-Regional IOUs, independent power producers, aggregators and marketers; in-Region purchasers of Federal System power such as Preference Customers and DSIs; and generators, power marketers and utilities that seek to transmit power into, out of, or through the Region.

Bonneville constructed the Federal transmission system and is responsible for its operation and maintenance, and makes investments necessary to maintain the electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by regional reliability practices. From time to time, Bonneville undertakes investments or reinforcements to or changes in the planning and operation of its transmission facilities to comply with the transmission system reliability criteria.

Bonneville continually monitors its transmission system and evaluates cost-effective responses needed for system stability and reliability on a long-term planning basis. A number of conditions, actions, and events could affect the electric transfer capability of Bonneville's transmission system and diminish the capacity of the system to a level that could require remedial measures. For example, operating conditions such as weather, system outages and changes in generation and load patterns, may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of users of the Federal transmission system, including Bonneville's Power Business Line. To assure that Bonneville's transmission system is adequate to meet needs, Bonneville periodically reviews the system to determine whether or not to make transmission infrastructure investments. For a discussion of proposed changes in law that could affect Bonneville's use of third party sources of capital to finance such investments see "—Proposals for Federal Legislation and Administrative Action Relating to Bonneville," and "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2005 Developments—President's Fiscal Year 2006 Budget."

While Bonneville has focused its transmission infrastructure efforts primarily on transmission projects needed to maintain reliability, other transmission projects are proposed that will provide additional, long-term firm transmission service for new power generation ("generation integration projects"). These transmission project proposals are on hold but are expected to move forward when funding approaches can be finalized. With regard to the financing of the foregoing generation integration projects, Bonneville's current policy is to require that those applicants requesting that Bonneville provide transmission for new generating facilities bear the risk of stranded transmission interconnection costs by prepaying the related transmission investments and obtaining credits to their transmission bills from Bonneville.

Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $300 million a year over the four fiscal years commencing October 1, 2004. To finance the foregoing investments, Bonneville expects to use a mix of United States Treasury borrowing and advance payments from transmission customer for use of the facilities being constructed. It is possible that Bonneville may also enter into capitalized lease-purchase arrangements to acquire such facilities.

Non-discriminatory Transmission Access and Separation of the Business Lines

In general, the thrust of regulatory changes in the 1990s, both by Congress and FERC, has been to encourage transmission owners to provide open transmission access to their transmission systems on terms that do not discriminate in favor of the transmission owner's own power-marketing functions. EPA-1992 amended sections 211/212 of the Federal Power Act to authorize FERC to order a "transmitting utility" to provide access to its transmission system at rates, and upon terms and conditions, that are just and reasonable, and not unduly discriminatory with respect to the transmitting utility's own use of its transmission system.

While Bonneville is not generally subject to the Federal Power Act, Bonneville is a "transmitting utility" under the EPA-1992 amendments to sections 211/212 of the Federal Power Act. Therefore FERC may order Bonneville to provide others with transmission access over the Federal System transmission facilities. FERC's authority also includes the ability to set the terms and conditions for such FERC-ordered transmission service. However, the transmission rates for FERC-ordered transmission under EPA-1992 are governed only by Bonneville's other applicable laws, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. Based on the legislative history relating to the provisions of EPA-1992 applicable to Bonneville, Bonneville's General Counsel is of the opinion that Bonneville's rates for FERC-ordered transmission services under sections 211/212 are to be established by Bonneville, rather than by FERC, and reviewed by FERC through the same process and using the same statutory requirements of the Northwest Power Act as are otherwise applicable to Bonneville's transmission rates.

In April 1996, FERC issued an order, "Order 888," to promote competition in wholesale power markets. Among other things, Order 888 established a *pro forma* tariff providing the terms and conditions for non-discriminatory open access transmission service, and required all jurisdictional utilities to adopt the tariff. Order 888 also included a "reciprocity" provision that allows non-jurisdictional utilities to obtain non-discriminatory open access from transmitting utilities if the non-jurisdictional utility submits to FERC for its approval (i) an open access transmission tariff that substantially conforms to the *pro forma* tariff and (ii) transmission rates that are comparable to the rates the non-jurisdictional utility applies to itself.

Bonneville is a non-jurisdictional utility. Notwithstanding the limited applicability of FERC Order 888 to Bonneville, however, in 1996, Bonneville voluntarily adopted terms and conditions for a non-discriminatory open access transmission tariff and filed such tariff with FERC seeking a reciprocity order. Bonneville's tariff offers transmission service to Bonneville's Power Business Line and other transmission users at the same tariff terms and conditions, and at the same rates. In March 1999, FERC found the tariff to be an acceptable reciprocity tariff. Bonneville has since revised and filed with FERC a new, open access tariff that conforms more closely to FERC's current *pro forma* open access tariff. In orders issued in March 2001 and September 2001, FERC found Bonneville's new tariff to be an acceptable reciprocity tariff. The revised open access transmission tariff became effective beginning October 1, 2001.

In April 1996, FERC also issued an order ("Order 889") that sets forth "standards of conduct" for jurisdictional utilities that are transmission providers and have a power-marketing affiliate or function. In general, these standards of conduct are intended to assure that wholesale power marketers that are affiliated with a transmission owner do not obtain unfair market advantage by having preferential access to information regarding the transmission owner's transmission operations. While not subject to Order 889, Bonneville nonetheless separated its transmission and power functions into separate business lines in conformance with that order and has developed and submitted standards of conduct for FERC's review. FERC found Bonneville's standards of conduct to be acceptable in February 1999.

Bonneville's Transmission and Ancillary Service Rates

Under the Northwest Power Act, Bonneville sets transmission rates, in accordance with sound business principles, that recover the cost associated with the transmission of electric power over the Federal System transmission facilities, including amortization of the federal investment in the Federal transmission system over a reasonable number of years, and other costs and expenses during the rate period. FERC confirms Bonneville's transmission rates after a finding that such rates recover Bonneville's costs and expenses during the rate period, and are sufficient to make full and timely payments to the United States Treasury.

Bonneville's transmission rates must also equitably allocate the cost of the Federal transmission system between Federal System power and non-federal power using the transmission system. Since 1996, the Power Business Line and customers transmitting Federal System power are charged the same transmission rates as are charged customers transmitting non-federal power. In compliance with the statutory requirements for its rates, Bonneville separately accounts for transmission and power revenues and costs. Since 1996, it also sets separate transmission and power rates to recover their respective costs.

Bonneville's transmission and ancillary services rates for fiscal years 2004-2005 were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. In addition to approving Bonneville's transmission rates under the Northwest Power Act, FERC stated that the rates and tariffs fulfill standards for open, nondiscriminatory transmission access. The 2004 transmission rates were not challenged in litigation. In Fall 2004, Bonneville commenced proceedings for transmission rates and tariffs for the next transmission rate period beginning October 1, 2005. In January 2005, Bonneville and its transmission customers signed a 2006 transmission rate case settlement agreement. Under the agreement, Bonneville would raise transmission rates on average by about 12.5 percent. While Transmission Business Line costs have increased somewhat, transmission sales are expected to be lower than in the recent past because transmission customers are increasingly remarketing their transmission rights on the Federal transmission system, and there have been electric power industry-wide economic changes that have reduced the number of transmission users and the number of power transactions requiring transmission rights and access. Bonneville's transmission rates vary depending on type of service purchased.

Bonneville's Participation in a Regional Transmission Organization

Following the issuance in May 1999 of a notice of proposed rulemaking on regional transmission organizations ("RTOs"), in January 2000 FERC issued a final rule on RTOs that establishes minimum characteristics and functions for an RTO and requires that each jurisdictional utility make certain filings regarding the formation of and participation in an RTO.

Between early 2000 and 2002, jurisdictional Regional transmission owners and Bonneville developed a proposal for a Northwest RTO, to be named RTO West, and made various filings with FERC. FERC approved significant portions of the proposal in orders issued in April 2001 and September 2002. After attempting to resolve remaining issues among themselves and determining that additional Regional support was necessary, the transmission owners, including Bonneville, in Spring 2003 resumed their engagement with Regional stakeholders through a "Regional Representatives Group" process to develop a more broadly supported RTO proposal. This process generated a proposal in late 2003 for an independent transmission entity that would begin with a more limited scope of operation than that proposed for RTO West and that would be subject to increased member control. Bonneville continues to participate in discussions with the Regional Representatives Group to further define this proposal.

In December 2004, Bonneville and eight other entities owning transmission facilities in the northwestern United States and in British Columbia unanimously voted to adopt bylaws for a new organization named Grid West. Various decisions are scheduled to be made about whether to continue this effort, including a decision scheduled for September 2005 on whether to establish an independent, developmental board of directors that would further develop the proposal. Assuming the effort moves forward, Bonneville would not make a decision about including Bonneville's transmission facilities in the Grid West program until late 2007 or early 2008. No filings have been made with FERC with respect to this proposal and none are currently being prepared.

In February 2005, Public Utility District No. 1 of Snohomish County, Washington , a large Preference Customer, filed a petition in the Ninth Circuit Court challenging Bonneville's authority to (i) fund the development of Grid West, (ii) sub-delegate its authorities to Grid West, and (iii) terminate its development of an environmental impact statement relating to the development of certain transmission service policies.

MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards

Bonneville is required to periodically review and, as needed, to revise rates for power sold and transmission services provided in order to produce revenues that recover Bonneville's costs, including its payments to the United States Treasury. The Northwest Power Act incorporates the provisions of other Bonneville organic statutes, including the Transmission System Act and the Flood Control Act. The Transmission System Act requires, among other things, that Bonneville establish its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment to the United States Treasury. Substantially the same requirements are set forth in the Flood Control Act.

Bonneville Ratemaking Procedures

The Northwest Power Act contains specific ratemaking procedures used to develop a full and complete record supporting a proposal for revised rates. The procedures include publication of the proposed rate(s), together with a statement of justification and reasons in support of such rate(s), in the Federal Register and a hearing before a hearing officer. The hearing provides an opportunity to refute or rebut material submitted by Bonneville or other parties and also provides a reasonable opportunity for cross-examination, as permitted by the hearing officer. Upon the conclusion of the hearing, the hearing officer certifies a formal hearing record (including hearing transcripts, exhibits and such other materials and information as have been submitted during the hearing) to the Bonneville Administrator. This record provides the basis for the Administrator's final decision, which must include a full and complete reasoning in support of the proposed rate(s).

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

Rates established by Bonneville under the Northwest Power Act may become effective only upon confirmation and approval by FERC, although FERC may grant interim approval of Bonneville's proposed rates pending FERC's final confirmation and approval.

FERC's review of Bonneville's firm power rates, Regional non-firm energy rates and transmission rates involves three standards set out in the Northwest Power Act. These standards require FERC to confirm and approve these Bonneville rates based on findings that such rates: (1) are sufficient to assure repayment of the federal investment in the Federal System over a reasonable number of years after first meeting Bonneville's other costs; (2) are based on Bonneville's total system costs; and (3) insofar as transmission rates are concerned, equitably allocate the costs of the federal transmission system between federal and non-federal power utilizing such system. FERC does not, however, review Bonneville's rate design or the cost allocation for rates for firm power and Regional non-firm energy. For a discussion of FERC regulations related to transmission access and rates, see "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines."

In confirming and approving Bonneville's rates for non-firm energy sold for use outside the Region, FERC reviews whether such rates were designed: (1) having regard to the recovery of cost of generation and transmission of such electric energy; (2) so as to encourage the most widespread use of Bonneville power; (3) to provide the lowest possible rates to consumers consistent with sound business principles; and (4) in a manner which protects the interests of the United States in amortizing its investments in the Federal System within a reasonable period. The Northwest Power Act provides for the possibility of an additional rate hearing before FERC on non-regional non-firm energy rates, based on the record developed at Bonneville.

Upon reviewing Bonneville's rates, FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a rate in lieu of a proposed rate that FERC finds does not meet the applicable standards. In the opinion of Bonneville's General Counsel, if FERC were to reject a proposed Bonneville rate, FERC would be limited to remanding the proposed rate to Bonneville for further proceedings as Bonneville deems appropriate. On remand, Bonneville would have to reformulate the proposed rate to comply with the statutory ratemaking standards. If FERC were to have given Bonneville interim approval, Bonneville may be required to refund the difference between the interim rate charged and any such final, FERC-approved rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Judicial Review of Federal Energy Regulatory Commission Final Decision

FERC's final approval of a proposed Bonneville rate is a final action subject to direct, exclusive review by the Ninth Circuit Court. Suits challenging final actions must be filed within 90 days of the time such action is deemed final. The record upon review by the court is limited to the administrative record compiled in accordance with the Northwest Power Act.

Unlike FERC, the court reviews all of Bonneville's ratemaking for conformance with all Northwest Power Act standards, including those ratemaking standards incorporated by reference in the Northwest Power Act. In the opinion of Bonneville's General Counsel, the court lacks the authority to establish a Bonneville rate. Upon review, the court may either affirm or remand a rate to FERC or Bonneville, as appropriate. On remand, Bonneville would have to reformulate the remanded rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville may be subject to refund obligations if the reformulated rate were lower than the remanded rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Power Customer Classes. The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (1) to public and certain federal agency customers; (2) to direct service industrial customers; and (3) for those portions of their load which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program." The rates for power sold to these respective customers classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

Other Firm Power Rates. Bonneville's rates for other firm power sales within the Region are based on the cost of such resources as Bonneville may decide are applicable to such sales. Bonneville also sells similarly priced surplus firm power outside the Northwest, primarily to California, under short-term power sales that allow for flexible prices, or under long-term contract rates.

Non-Firm Energy. Non-firm energy is priced in accordance with the statutory standards (contained in the Northwest Power Act) applicable to such sales, as discussed above. Non-firm energy is available within and without the Pacific Northwest, with most sales being made to California utilities that use non-firm energy to displace the operation of more expensive thermal resources.

Limitations on Suits Against Bonneville

Suits challenging Bonneville's actions or inaction may only be brought pursuant to certain federal statutes that waive sovereign immunity. These statutes limit the types of actions, remedies available, procedures to be followed and the proper forum. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville is a judgment for money damages. See "BONNEVILLE LITIGATION" for information regarding pending litigation seeking to compel or restrain action by Bonneville.

Laws Relating to Environmental Protection

Bonneville must comply with the National Environmental Policy Act ("NEPA"), which requires that federal agencies conduct an environmental review of a proposed federal action and prepare an environmental impact statement if the action proposed may significantly affect the quality of the human environment. NEPA may require that Bonneville follow statutory procedures prior to deciding whether to implement an action. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Toxic Substance Control Act ("TSCA") and applicable state statutes and regulations, as well as amendments thereto, may result in Bonneville incurring unplanned costs to investigate and clean up sites where hazardous substances have been released or disposed of. There are currently two such sites. One site is a Bonneville-operated facility awaiting determination by the EPA. The other is a non-Bonneville site wherein Bonneville has been identified as potentially a responsible party. Normally environmental protection costs are budgeted and do not exceed $150,000 per site. While Bonneville anticipates that additional potential costs will total between $1 million and $2 million over several years, Bonneville cannot assure the ultimate level of costs that may be incurred under these statutes.

Other Applicable Laws

Many statutes, regulations and policies are or may become applicable to Bonneville, several of which could affect Bonneville's operations and finances. Bonneville cannot predict with certainty the ultimate effect such statutes, regulations or policies could have on its finances.

Columbia River Treaty

Bonneville and the Corps have been designated by executive order to act as the "United States Entity" which, in conjunction with the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River Basin for the purposes of power generation and flood control.

Regulation of stream flows by the Canadian reservoirs enables six federal and five non-federal dams downstream in the United States to generate more usable, firm electric power. This increase in firm power is referred to as the "downstream power benefits." The Treaty specifies that the downstream power benefits be shared equally between the two countries. Canada's portion of the downstream power benefits is known as the "Canadian Entitlement."

The Treaty specifies that the Canadian Entitlement be delivered to Canada at a point on the border near Oliver, British Columbia, unless the United States Entity and the Canadian Entity agree to other arrangements. The United States Entity and Canadian Entity signed the "Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 15, 2024" (the "Entity Agreement") on November 20, 1996, which was subsequently revised on March 29, 1999. As a result, the United States Entity does not have to build the proposed transmission line to a point near Oliver, British Columbia, in order to return the Canadian Entitlement.

The United States Entity and Canadian Entities have consulted on terms for possible disposal of portions of the Canadian Entitlement in the United States. Direct disposal of the Canadian Entitlement in the United States was authorized by the executive branches of the United States and Canadian governments through an exchange of diplomatic notes, which occurred on March 29, 1999. The United States Entity's obligation to return the Canadian Entitlement to the border under the Entity Agreement is not dependent upon the authority to directly dispose of the Canadian Entitlement in the United States.

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of its current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in Congress have included privatizing the federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at federal hydroelectric projects, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates and submitting Bonneville's power marketing to varying degrees of FERC regulation. None of these bills or proposals were enacted into law.

On February 2, 2005, President Bush issued the budget for Federal Government for fiscal year 2006. The President's Fiscal Year 2006 Budget includes a proposal for legislation that calls "for certain nontraditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville's] statutory debt limit." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Nonetheless, the budget provides that the proposal would only affect those transactions occurring after enactment of the legislation. In addition, the Department of Energy has agreed that the proposed legislation will not affect Bonneville's ability to participate in the refinancing of debt it secures pursuant to transactions that Bonneville entered into prior to the date the proposed legislation takes effect.

The President's Fiscal Year 2006 Budget also includes a proposal for legislation "to very gradually bring [the federal power marketing administrations', including Bonneville's] electricity rates closer to average market rates throughout the country." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Bonneville is unable to predict whether such legislation will be introduced in, or enacted into law by, Congress.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such proposals, if enacted, could affect Bonneville's obligations with respect to the Series 2005 Bonds. However, Bonneville believes that any major electric industry restructuring affecting its obligations with respect to the Series 2005 Bonds would require federal legislation. It is also possible that parties may propose terms that could, if implemented, have an adverse impact on the tax-exempt status of the Series 2005A Bonds.

Bonneville is a federal agency. It is subject to direction or guidance in a number of respects from the U.S. Office of Management and Budget, DOE, FERC, the United States Treasury and other federal agencies. Bonneville is frequently the subject of, or would be otherwise affected by, various executive and administrative proposals. Bonneville is unable to predict the content of future proposals; however, it is possible that such proposals could materially affect Bonneville's operations and financial condition.

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

Prior to 1974, Congress annually appropriated funds for the payment of Bonneville's obligations, including working capital expenditures. Under the Transmission System Act, Congress created the Bonneville Fund, a continuing appropriation available to meet all of Bonneville's cash obligations.

All receipts, collections and recoveries of Bonneville in cash from all sources are now deposited in the Bonneville Fund. These include revenues from the sale of power and other services, trust funds, proceeds from the sale of bonds by Bonneville to the United States Treasury (see "—Bonneville Borrowing Authority"), any appropriations by Congress for the Bonneville Fund and any other Bonneville cash receipts.

Bonneville is authorized to make expenditures from the Bonneville Fund without further appropriation and without fiscal year limitation if such expenditures have been included in Bonneville's annual budget to Congress. However, Bonneville's expenditures from the Bonneville Fund are subject to such directives or limitations as may be included in an appropriations act. Bonneville's annual budgets are reviewed and may be changed by the DOE and subsequently by the federal Office of Management and Budget. The Office of Management and Budget, after providing opportunity for Bonneville to respond to proposed changes, includes Bonneville's budget in the President's budget submitted to Congress.

The existence of the Bonneville Fund also enables Bonneville to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount of cash in the Bonneville Fund and available borrowing authority. Pursuant to the Project Act, Bonneville has broad authority to enter into contracts and make expenditures to accomplish its objectives.

No prior budget submittal, appropriation, or any prior Congressional action is required to create such obligations except in certain specified instances. These include construction of transmission facilities outside the Northwest, construction of major transmission facilities within the Northwest, construction of certain fish and wildlife facilities, condemnation of operating transmission facilities and acquisition of a major resource that is not consistent with the Power Plan.

The Federal System Investment

The total cost of the multipurpose Corps and Bureau projects is allocated among the purposes served by the projects, which may include flood control, navigation, irrigation, municipal and industrial water supply, recreation, the protection, mitigation and enhancement of fish and wildlife, and the generation of power. The costs allocated to power generation from the Corps and Bureau projects as well as the cost of the transmission system prior to 1974 have been funded through appropriations. The capital costs of the transmission system since 1974, in addition to certain capital conservation and fish and wildlife costs since 1980, have been funded through the use of Bonneville's borrowing authority with the United States Treasury.

Bonneville is required by statute to establish rates that are sufficient to repay the federal investment in the power facilities of the Federal System within a reasonable period of years. The statutes, however, are not specific with regard to directives for the repayment of the Federal System investment, including what constitutes a reasonable period of years. Consequently, the details of the repayment policy have been established through administrative interpretation of the basic statutory requirements. The current administrative interpretation is embodied in the United States Secretary of Energy's directive RA 6120.2. The directive provides that Bonneville must establish rates that are sufficient to repay the federal investments within the average expected service life of the facility or 50 years, whichever is less. Bonneville develops a repayment schedule both to comply with investment due dates and to minimize costs over the repayment period. Costs are minimized in accordance with the United States Secretary of Energy's directive RA 6120.2 by repaying the highest interest-bearing investments first, to the extent possible. This method of determining the repayment schedule would result in some investments being repaid before their due dates, while assuring that all investments will be repaid by their due dates. As of September 30, 2004, Bonneville had repaid $6.6 billion of principal of the Federal System investment and has $4.4 billion principal amount outstanding with regard to such appropriated investments.

Bonneville Borrowing Authority

In February 2003, Congress enacted and the President signed into law a $700 million increase in Bonneville's authority to borrow from the United States Treasury. The new law increased to $4.45 billion the aggregate principal amount of bonds Bonneville is authorized to sell to the United States Treasury and to have outstanding at any one time. The new increment of borrowing authority is to be used for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.90 billion of bonds were outstanding as of September 30, 2004. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 average megawatts. Of the $4.45 billion in United States Treasury borrowing authority, $1.25 billion is available for renewable resources and conservation purposes and $3.2 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. As of September 30, 2004, the interest rates on the outstanding bonds ranged from 2.30% to 8.55% with a weighted average interest rate of approximately 4.87%. The original terms of the outstanding bonds vary from 3 to 40 years. The term of the bonds is limited by the average expected service life of the associated investment: 40 years for transmission facilities, 75 years for Corps and Bureau capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. Bonds can be issued with 5-year call options. As of September 30, 2004, Bonneville had four callable bonds on its books totaling $228.9 million.

Debt Optimization Proposal

In the spring of 2000, Bonneville presented a "Debt Optimization Proposal" (or "Bonneville Proposal") to Energy Northwest. The proposal, which was agreed to by Energy Northwest, involves the extension of the final maturity of debt issued for the Columbia Generating Station. In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it also incorporated an increase in the average life of outstanding bonds issued for Projects 1 and 3 (as defined below) as a refinancing program objective for any future refinancing of such bonds. .

Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's rate payers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs at the lowest cost to rate payers; and (3) maintaining sufficient financial flexibility to handle Bonneville's financial requirements. Implementing the proposal is intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's high interest Federal debt and reduce Bonneville's overall fixed costs. Under the Debt Optimization Proposal through July 1, 2004, approximately $1 billion in maturing bonds issued by Energy Northwest for the Energy Northwest Net Billed Projects have been refinanced with new bonds having final maturities in calendar years 2013-2018. Bonneville expects that Energy Northwest will continue to undertake similar refinancings through at least fiscal year 2008.

Order in Which Bonneville's Costs Are Met

Bonneville's operating revenues include amounts equal to net billing credits provided by Bonneville under the Two-Party and Three-Party Net Billing Agreements (collectively, the "Trojan Net Billing Agreements") and the Energy Northwest Net Billing Agreements, to certain of its customers in return for payments by such customers to Energy Northwest to meet certain costs of the Energy Northwest Net Billed Projects, and to the Issuer to meet certain costs of the Trojan Nuclear Project. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Trojan and Energy Northwest Net Billing Agreements for the Trojan Nuclear Project and the Energy Northwest Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayment of appropriated amounts to the Corps and the Bureau for costs that are allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2004 payment responsibility to the United States Treasury in full and on time. Of

Bonneville's payments of $1.053 billion in fiscal year 2004, approximately $346 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Proposal through the use of cash flows derived from reduced debt service in such fiscal year for the Energy Northwest's Project 1, Project 3 and Columbia Generating Station. Such Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. In accordance with the Debt Optimization Proposal, Bonneville plans to make similar advance amortization payments to the United States Treasury in fiscal year 2005 and in subsequent fiscal years.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Trojan Net Billing Agreements securing the Series 2005 Bonds, payments, if any, under the 2005 Letter Agreement and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may only make payments to the United States Treasury from net proceeds; all other cash payments of Bonneville, including cash deficiency payments under the Trojan Net Billing Agreements securing the Series 2005 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

Bonneville is authorized to enter into new agreements to provide for additional net billing of its customers' bills. Nevertheless, because Bonneville is now able to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount in the Bonneville Fund and available borrowing authority, the primary reason for using net billing no longer exists. Bonneville has no present plans to enter into new agreements requiring net billing to fund resource acquisitions or other capital program investments.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of payments to the United States Treasury in the event that net proceeds were not sufficient for Bonneville to make its annual payment in full to the United States Treasury. This could occur if Bonneville were to receive substantially less revenue or incur substantially greater costs than expected.

Under the repayment methodology as specified in the United States Secretary of Energy's directive RA 6120.2, amortization of the Federal System investment is paid after all other cash obligations have been met. If, in any year, Bonneville has insufficient cash to make a scheduled amortization payment, Bonneville must reschedule amortization payments not made in that year over the remaining repayment period. If a cash under-recovery were larger than the amount of planned amortization payments, Bonneville would first reschedule planned amortization payments and then defer current interest payments to the United States Treasury. When Bonneville defers an interest payment, the deferred amount is assigned a market interest rate determined by the Secretary of the United States Treasury and must be repaid before Bonneville may make any other repayment of principal to the United States Treasury. See the table under the heading "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" for historical United States Treasury payments.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both the Bureau and the U.S. Fish and Wildlife Service ("Fish and Wildlife Service") to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Bureau federal system operations and maintenance activities. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2004 were $60 million for the Bureau, $138 million for the Corps, and $17 million for the Fish and Wildlife Service.

Bonneville believes that, in contrast to prior practice, the direct payment approach increases Bonneville's influence on the Corps' and the Department of Interior's Federal System operations and maintenance activities, expenses and budgets because, in general, Bonneville's approval becomes necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct payments would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct payments could be made to the exclusion of non-federal payments that would otherwise have been paid under historical practice. A result of any direct payment obligation by Bonneville is that there would be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, during the terms of the direct payment agreements, Bonneville expects to have roughly $500 to $800 million in scheduled annual payments to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses.

Within Fiscal Year Prepayments of Appropriations Repayment Obligations.

As part of Bonneville's continuing effort to control costs Bonneville has examined a number of internal proposals to improve its cash management. One opportunity that Bonneville has examined is the prepayment within a fiscal year of certain outstanding appropriations repayment obligations that would otherwise be repaid at the end of such fiscal year. Depending on circumstances at the time, such prepayments may enable Bonneville to obtain net interest savings because interest earnings on amounts in the Bonneville Fund may be lower than the interest accruing on the related appropriations repayment obligations.

The prepayments at issue relate to Bonneville's repayment obligations for Federal System appropriations associated with physical assets that have reached the end of their designated useful lives and are thus "due" for repayment. By law, Bonneville is to set its power and transmission rates to recover revenues sufficient to assure repayment of such appropriated investments within their designated useful lives, as established in some cases by statute and in other cases by administrative policy reflected in Secretary of Energy's directive RA 6120.2. Bonneville refers to such repayment obligations as "due appropriations repayment obligations." They can be contrasted with other appropriation repayments, which, by operation of administrative policy reflected in Secretary of Energy's directive RA 6120.2, may become scheduled for repayment in advance of the end of their repayment periods. Bonneville does not propose to prepay within a fiscal year such scheduled, but not due, appropriated repayment obligations.

While Bonneville has historically made intra-fiscal-year payments with respect to due payments on bonds issued to the United States Treasury, in great part for scheduled semi-annual interest payments on such bonds, the prepayment of due appropriations repayment obligations within a fiscal year departs from Bonneville's historical practice. Under historical practice Bonneville would pay such due appropriations repayment obligations only at the end of a fiscal year. By contrast to historical practice, within-fiscal-year prepayments of due appropriations repayment obligations would reduce the reserves in the Bonneville Fund available to meet non-Federal obligations during the remainder of the subject fiscal year to the extent of such prepayments. Nonetheless, the interest savings would increase Bonneville's financial reserves over what they otherwise would have been at the end of the subject fiscal year.

In the second quarter of fiscal year 2004, Bonneville prepaid by about eight months approximately $73 million principal amount of appropriations repayment obligations that were due at the end of that fiscal year. Prior to making the above mentioned prepayment, Bonneville concluded that it had in excess of a 99 percent probability of making its full scheduled fiscal year 2004 payments to the United States Treasury and a slightly greater probability of making the subject appropriations repayment obligations in full in fiscal year 2004, after taking into account the interest savings to be achieved through early payment. Bonneville is not planning to make any such early appropriations repayments in fiscal year 2005.

Bonneville has yet to determine whether and the circumstances under which it would take advantage of similar interest savings opportunities in future fiscal years. Bonneville estimates it will have between $10 and $110 million per year in due appropriations repayment obligations over the next five years bearing interest at rates that may offer similar interest savings opportunities. Whether and the extent to which Bonneville will make similar advance payments of due appropriations obligations in the future will depend on the facts and circumstances at the time, but Bonneville expects it will do so only in years when it would have a near certainty of meeting its annual repayment obligations in full to the United States Treasury. Under Secretary of Energy's directive RA 6120.2, due appropriation repayment obligations have the highest priority for payment among all of Bonneville's appropriation repayment responsibilities and hence would be the last of such payments to be rescheduled if Bonneville were to miss scheduled payments to the United States Treasury. For a brief discussion of Secretary of Energy's directive RA 6120.2 see "—The Federal System Investment" and "—Order in Which Bonneville's Costs Are Met."

For a discussion of the effects of intra-fiscal-year payments relating to the Corps, Bureau and certain other expenses see "—Direct Funding of Federal System Operations and Maintenance Expense."

Hedging and Derivative Instrument Activities and Policies

Bonneville's financial success depends on its ability to manage business and financial risks associated with its commercial operations in a changing competitive environment. Effective management of electricity, interest rate and natural gas price risk can assist in efforts to manage Bonneville's revenues and expenses.

Bonneville is affected by price risk associated with commodities and streamflow uncertainty that in turn affect the predictability and stability of its revenues. These commodities include electricity, and natural gas, and to a much lesser extent than was the case historically, aluminum. Bonneville desires to manage price and revenue risks resulting from electricity and natural gas volatility, hydro supply uncertainty and interest rate risk.

Bonneville seeks to ensure that its hedging of various revenue and price risks be conducted in an intelligent, business-like manner. To this end, Bonneville adopted its Hedging Policy, as amended from time to time, to describe the guidelines, controls and management structure when there is a decision to hedge price and revenue risk in financial instruments. Bonneville's Hedging Policy allows the use of financial instruments such as commodity futures, options and swaps used to hedge price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development, and interest rates. From time to time, Bonneville uses or may use financial instruments in the form of Over-the-Counter electricity swap agreements and options, Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy, and interest rate swaps to hedge interest rate positions or to more efficiently manage Bonneville's overall debt portfolio. In general, the Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under certain procedures set forth in the Policy. In addition, the Policy set forth a limited exception for the use of financial instruments relating to interest rate management techniques to manage Bonneville's interest rate costs, including by means of interest rate swaps to effect the synthetic refunding of Bonneville's direct and indirect debt obligations. The Policy does not apply to physical (power) transactions

In January 2003, Bonneville entered into two floating to fixed interest rate swap agreements with an aggregate notional amount of $500 million. The swap agreements were entered into in connection with, and are in an aggregate notional principal amount approximately equal to, the principal amount of certain variable rate bonds issued by Energy Northwest in April 2003 (the "Related Bonds"). Pursuant to these swap agreements, Bonneville is required to make fixed rate payments to each of two swap providers and will receive variable rate payments from such swap providers. One of the swaps has a term of ten years and the other has a term of fifteen years. The Related Bonds are variable rate bonds having final maturities of approximately fifteen years. Under certain circumstances, Bonneville and/or the swap provider may terminate the respective swap agreement, at which time Bonneville may be required to make a payment to the swap provider depending on the mark-to-market value of the swap at termination. Each of the swap providers is currently rated at or above the "Aa" category by Moody's Investor Service and at or above the "AA" category by Standard & Poor's Credit Market Services, a Division of The McGraw-Hill Companies Inc.

Historical Federal System Financial Data

Federal System historical financial data for fiscal years 2002 through 2004 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information has been derived from the annual audited financial statements of the Federal System and should be read in conjunction with Appendix B-1. Federal System financial statements are prepared in conformity with generally accepted accounting principles. The audited Financial Statements of the Federal System (which include accounts of Bonneville as well as those of the generating facilities of the Corps and the Bureau for which Bonneville is the power marketing agency) for the fiscal year ended September 30, 2004 are included as Appendix B-1 to the Official Statement. The unaudited quarterly financial report for the three months ended December 31, 2004 is included as Appendix B-2.

Federal System Statement of Revenues and Expenses
(Actual Dollars in Thousands)

Fiscal year ending September 30,	2004	2003	2002
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-owned utilities [(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
Book-outs [(3)]	(212,155)	0	0
Total Sales of Electric Power	2,470,428	2,806,780	2,873,293
Transmission [(4)]	535,936	552,718	566,654
Fish Credits and other revenues [(5)]	191,547	252,606	93,782
Total Operating Revenues	3,197,911	3,612,104	3,533,729
Operating Expenses:			
BPA O&M [(6)]	613,121	607,616	775,077
Purchased Power [(3)]	582,129	1,043,009	1,286,867
Corps, Bureau and Fish & Wildlife O&M [(7)]	214,035	198,539	198,055
Non-Federal entities O&M — net billed [(8)]	221,210	208,535	167,026
Non-Federal entities O&M — non-net billed [(9)]	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
Non-Federal Projects Debt Service [(10)]	248,475	119,534	230,175
Federal Projects Depreciation	366,239	350,025	335,205
Residential Exchange [(11)]	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 [(12)]	(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/(Expenses)	$ 504,415	$ 555,424	$ 9,475
Total Sales (unaudited) — average megawatts (Ne of Residential Exchange Program)	9,772	10,764	11,732

(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 Bonneville 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 ("FASB"). 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 book-outs were to be reported on a "gross" basis. Application of the new guidance thus decreased both operating revenues and purchase power expense by $212 million but had no effect on the net revenue, cash flows or margins.

(4) Bonneville obtains revenues from the provision of transmission and other related services.

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife credits Bonneville receives to its United States Treasury repayment obligation. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. In addition, under FASB Statement of Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville also recorded as revenue in Fiscal Years 2002, 2003 and 2004, positive Mark-to-Market Amounts of $38.4 million, $55.3 million and $89.5 million, respectively. See Footnote 11 below.

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

(7) Corps, Bureau and Fish & Wildlife operations and maintenance expenses include the costs of the Corps and Bureau generating projects and expenses of the U.S. Fish & Wildlife Service, in connection with the Federal System.

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

(9) 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 Bonneville has agreed to purchase under certain capitalized contracts, the costs of which are not net billed.

(10) These amounts include payment by Bonneville 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 the Columbia Generating Station, and the Issuer's 30 percent ownership share of the Trojan Nuclear Project. These amounts also include payment by Bonneville with respect to several small generating and conservation projects.

(11) See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line" and "—Residential Exchange Program."

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

Management Discussion of Operating Results

Fiscal Year 2004. Bonneville had net revenues of $504 million in fiscal year 2004, a decrease of approximately $51 million from fiscal year 2003. The Debt Optimization Program and other debt management actions contributed significantly to sustaining positive net revenues. Without the positive net revenue effects of that program and of the positive, non-cash revenue effects arising from the accounting treatment of certain transactions under Financial Accounting Standards Board ("FASB") Statement of Accounting Standard No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), net revenues would have been $66 million in fiscal year 2004. Under SFAS 133, Bonneville recognized a gain of $89.5 million reflecting the difference between the mark to market value and the contracted price of certain derivatives not designated as hedging instruments.

With respect to power marketing, in fiscal year 2004, Bonneville's total operating expenses and revenues from electricity sales reflected for the first time the impacts of certain newly adopted accounting guidance from the Emerging Issues Task Force ("EITF") of the FASB. Under this new guidance (referred to herein as "EITF Issue No. 03-11"), which Bonneville adopted as of the quarter ending March 31 2004, 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 book-outs were to be treated on a "gross" basis. Application of the new guidance thus decreased both operating revenues from power sales and purchase power expense in fiscal year 2004 by $212 million from what they otherwise would have been absent application of the guidance. The accounting treatment under EITF Issue No. 03-11 had no effect on net revenue, cash flows or margins. Prospective application of EITF Issue No. 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts when compared with financial statements issued prior to the application of the guidance.

Total operating revenues in fiscal year 2004 when compared to fiscal year 2003 decreased by $414 million, or 11%, due to lower total power sales, reduced United States Treasury repayment credits for fish mitigation under section 4(h)(10)(C) of the Northwest Power Act, and a comparatively lower LB-CRAC percentage for the six month period beginning April 1, 2004. Total operating revenues were also affected by the application of EITF Issue No. 03-11 as discussed above.

The decrease in total power sales was largely caused by a decrease in power sales to Regional IOUs of $73 million, a 17% decrease, and decreased sales outside the Region of $139 million, a 22% decrease. Total power sales in fiscal year 2004 were lower when compared to fiscal year 2003, despite increased sales to Preference Customers of $15 million, or a 1% increase, and to DSI customers of $74 million, or a 400% increase. Power sales revenues and purchase power expense both declined substantially when compared to audited fiscal year 2003 results, notwithstanding that runoff conditions in both years was comparably below average. Revenue from power sales declined by $355 million in fiscal year 2004 when compared to fiscal year 2003. Much of the decline in such sales occurred because certain power purchases (including Augmentation Purchases) by Bonneville had either been fulfilled or restructured, thereby resulting in reduced amounts of power available to Bonneville for sale. As noted below, these purchase contract expirations and restructurings also reduced purchase power expense. As described above, application of new accounting guidance decreased reported revenues.

United States Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act, which are accounted as a component of total sales, decreased from $175 million in fiscal year 2003 to $77 million in fiscal year 2004 in part due to fully depleting the Fish Cost Contingency Fund in Fiscal Year 2003. The Fish Cost Contingency Fund was an amount of accumulated but unused monetary credits under section 4(h)(10)(C) which had been earned by Bonneville prior to fiscal year 1995. Under prior policy agreement among Federal agencies, those credits were to be used by Bonneville as credits to its United States Treasury payments under limited circumstances, including low water conditions. Low water conditions in fiscal year 2003 led to the use in that year of the remaining amounts of credits in the Fish Cost Contingency Fund and it is now fully and finally depleted. Notwithstanding the depletion of the Fish Cost Contingency Fund, Bonneville continues to accrue and use 4(h)(10(C) credits on an annual basis. Also, in fiscal year 2004, Bonneville received lower non-firm transmission revenues reflecting changes by customers in their transmission purchase and sales practices (i) as they purchased more transmission rights in the secondary market and less from Bonneville, and (ii) as the total volume of power transactions using Bonneville transmission system declined.

Total operating expenses in fiscal year 2004 were approximately $302 million lower when compared to fiscal year 2003, a decrease of about 11%, largely due to decreased Purchase Power in fiscal year 2004. Purchase Power decreased by $461 million, or by about 44%, as a result of the expiration of Purchase Power commitments of nearly 400 average megawatts. Total operating expenses were also affected by the application of EITF Issue No. 03-11, as discussed above.

Debt service for Non-Federal Projects increased $129 million, or 108 percent, primarily because fiscal year 2003 amortization of debt for Energy Northwest Net Billed Projects was comparatively low as a result of the Debt Optimization program and the embedded amortization schedule for such debt. In addition, in fiscal year 2003 Energy Northwest debt service was paid in part by funds made available when reserve funds for certain Energy Northwest Net Billed Bonds were replaced with surety agreements. Operations and maintenance increased $13 million and federal projects depreciation increased $16 million. Net interest expense on United States Treasury repayment obligation declined $61 million compared to fiscal year 2003 due to early amortization of some of such debt under the Debt Optimization program and to the generally lower interest rates on borrowings by Bonneville from the United States Treasury to finance Federal System generating and transmission projects.

For further information on fiscal year 2004 financial results see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Bonneville's Fiscal Year 2004 Financial Results."

Fiscal Year 2003. Bonneville had net revenues of $555 million in fiscal year 2003, an increase of approximately $546 million over fiscal year 2002. Implementation of the Debt Optimization Proposal and other debt management actions contributed significantly to the substantial increase in net revenues. Without the program, other debt management actions, and the effects of SFAS 133, net revenues would have been $37 million for fiscal year 2003. Total operating revenues in fiscal year 2003 increased by $78 million, or 2%, from the previous fiscal year because of greater sales to Regional IOUs and increased United States Treasury credits derived under section 4(h)(10)(C) of the Northwest Power Act for fish mitigation, even though there was both reduced hydro generation and reduced power sales when compared to fiscal year 2002. However, the average price for discretionary surplus power sales rose from $26 per megawatt hour to $37 per megawatt hour, an increase of 42%. United States Treasury credits under section 4(h)(10)(C) of the Northwest Power Act increased from $38 million to $175 million in 2003. Credits for fish mitigation increased due to below-average water conditions and increased power purchases that result from reduced hydro supply. For a description of 4(h)(10)(C) see "—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

Total operating expenses in fiscal year 2003 were approximately $461 million lower as compared to fiscal year 2002, a decrease of about 15%. This was largely due to decreased Non-Federal Projects Debt Service, which decreased by $111 million or 48% because of the deferral of some principal payments due in fiscal year 2003 into the future, primarily as a result of continued implementation of the Debt Optimization Proposal. Lower interest rates through refinancing some of the Non-Federal debt also contributed to the decline in debt service. Net Interest Expense on Federal debt declined by $7 million compared to fiscal year 2002 due to generally lower interest rates on borrowings from the United States Treasury to finance federal generating and transmission projects. Total operations and maintenance costs, excluding Purchased Power, also decreased by $121 million, or 10% from the previous year. Lower bad debt expense and general and administrative expense were the main factors that led to this decrease. Purchased Power also decreased by $244 million, or 19%, in view of comparatively lower prices for the power purchased by Bonneville and the release of Bonneville from certain power purchase commitments as the result of a settlement between Bonneville and Enron Power Marketing Corp. in its bankruptcy proceedings.

Fiscal Year 2002. In fiscal year 2002, Bonneville had net revenues of $9 million, an increase of approximately $347 million over fiscal year 2001 when Bonneville had net expenses of approximately $337 million. Total operating revenues declined by $745 million, or 17%, from the previous year due to lower market prices for discretionary sales of surplus power and a 94% decline in fish credits under section 4(h)(10)(C) of the Northwest Power Act. These lower market prices resulted in a decrease of $446 million, or 41%, in revenues from sales outside the Northwest. In addition, revenues from aluminum company DSIs decreased by $362 million, or 86%, largely due to the purchase back by Bonneville of some of its power sales to such DSIs and curtailments of purchases by some DSIs. The $323 million, or 46%, decline in revenues from Regional IOUs in fiscal year 2002 stemmed largely from payments arising under agreements between Bonneville and the Regional IOUs to settle Bonneville's Residential Exchange obligations and the purchase back by Bonneville of some of its power sales to Regional IOUs. This decline in revenues was somewhat mitigated by the amount of revenues from sales to publicly-owned utilities, which in fiscal year 2002 increased by $858 million, or 91%, due to a substantial rate increase at the beginning of the new rate period (October 1, 2002), and an increase in the amount of power Bonneville sold to this customer class. The $472 million, or 42%, decline over fiscal year 2001 in revenues from transmission and other related services was the result of lower estimated United States Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act as these repayment credits declined by 94% as noted immediately above. Applicable criteria did not permit use of the Contingency Fund whereas $247 million was drawn from the fund, in the form of United States Treasury repayment credits, during fiscal year 2001.

Total operating expenses in fiscal year 2002 were approximately $3.2 billion, a decrease of $944 million, or 23%, when compared to fiscal year 2001. This was largely due to lower market prices for power purchased by Bonneville. Purchased power expense declined by $1 billion, or 44%, in 2002, due to a 15% decrease in the amount of power purchased by Bonneville as water conditions returned to average levels from the historical low levels of the prior fiscal year, as well as a decrease in the average cost of purchased power. In addition, net billed debt service decreased by approximately $237 million, or 53%, due primarily to the refinancing and restructuring of a portion of the outstanding net billed debt. Non-Federal entities O&M-net billed expense declined by $42 million primarily due to reduced operating expense related to the Columbia Generating Station. However, Bonneville operations and maintenance expenses were up by $244 million dollars, or 46%, in fiscal year 2002, primarily due to increased budgets for fish and wildlife, resource conservation management and bad debt expense.

Statement of Non-Federal Project Debt Service Coverage

The Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments uses the Federal System Statement of Revenue and Expenses to develop a non-federal Project debt service coverage ratio ("Non-Federal Project Debt Service Coverage Ratio") which demonstrates how many times total non-federal Project debt service is covered by net funds available for non-federal Project debt service. Net funds available for non-federal Project debt service is defined as total operating revenues less operating expenses (see footnote 9 to the Statement of Non-Federal Project Debt Service Coverage below). Net funds available for non-federal Project debt service less total non-federal Project debt service yields the amount available for payment to the United States Treasury. This Non-Federal Project Debt Service Coverage Ratio does not reflect the actual priority of payments or distinctions between cash payments and credits under Bonneville's net billing obligations. For a discussion of certain direct payments by Bonneville for Federal System operations and maintenance, which payments reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see "—Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments
(unaudited)
(Actual Dollars in Thousands)

Fiscal Years ending September 30,	2004	2003	2002
Total Operating Revenues	$ 3,197,911	$ 3,612,104	$ 3,533,729
Less: Operating Expense(1)	1,579,896	2,042,991	2,408,520
Net Funds Available for Non-Federal Project Debt Service	1,618,015	1,569,113	1,125,209
Less: Total Non-Federal Project Debt Service(2)	248,475	119,534	230,175
Revenue Available for Treasury	1,369,540	1,449,579	895,034
Amount Paid to Treasury:			
Corps and Bureau O&M(3)	214,035	198,539	198,055
Net Interest Expense(4)	284,851	345,591	352,300
Capitalization Adjustment(5)	68,566	67,703	67,356
Allowance for Funds Used During Construction(4) (6)	21,584	18,641	15,061
Amortization of Principal	592,500	543,747	505,012
Total Amount Allocated for Payment to Treasury(7)	1,181,536	1,174,221	1,137,784
Revenues Available for Other Purposes(8)	188,004	275,358	(242,750)
Non-Federal Project Debt Service Coverage Ratio(9)	6.5	13.1	4.9
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio(10)	1.7	1.7	1.3

(1) Operating Expenses include the following items from the Federal System Statement of Revenues and Expenses: Bonneville O & M, Purchased Power, Non-Federal entities O & M-net billed, Non-Federal entities O & M non-net-billed, and the Residential Exchange Program. Operating Expenses do not include certain payments to the Corps and Bureau. Treatment of the Corps, Bureau and Fish & Wildlife Service operating expense is described in "—Direct Funding of Federal System Operations and Maintenance Expense."

(2) Includes net billed and non-net billed debt service. Non-net billed debt service amounted to $16.3 million, $15.2 million and $25.7 million for fiscal years 2002, 2003 and 2004, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Bureau and Fish & Wildlife for fiscal years 2002, 2003 and 2004. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(4) Amounts shown are calculated on an accrual basis.

(5) The capitalization adjustment is included in net interest expense but is not part of Bonneville's payment to the United States Treasury.

(6) The Allowance for Funds Used During Construction that Bonneville pays to the United States Treasury is Bonneville's portion of the interest component on the Federal investment during the construction period.

(7) Bonneville's payments to the United States Treasury in fiscal years 2002, 2003 and 2004 were $1.056 billion, $1.057 billion and $1.053 billion, respectively. In fiscal years 2002, 2003 and 2004, respectively, direct payments to the Corps, Bureau and Fish & Wildlife for operations and maintenance were included in the amount of (i) $132 million, $129 million and $138 million for the Corps, (ii) $51 million, $54 million and $60 million for the Bureau, and (iii) $15 million, $15 million and $17 million for Fish & Wildlife, respectively. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(8) Revenues Available For Other Purposes approximates the change in reserves from year to year. Reserves were $625 million at the end of fiscal year 2001 (not depicted) and $638 million at the end of fiscal year 2004.

(9) The “Non-Federal Debt Service Coverage Ratio” is defined as follows:

$$\frac{\text{Total Operating Revenues-Operating Expense (Footnote 1)}}{\text{Non-Federal Project Debt Service}}$$

(10) The “Non-Federal Debt Service plus Operating Expense Coverage Ratio” is defined as follows:

$$\frac{\text{Total Operating Revenues}}{\text{Operating Expense (Footnote 1) + Non-Federal Project Debt Service}}$$

Statement of Net Billing Obligations and Expenditures (unaudited)[1]
(Actual Dollars in Thousands)

Fiscal years ending September 30,	2004	2003	2002
Operating Revenues from Publicly-Owned Utilities[2]	$ 1,737,895	$ 1,723,341	$1,798,477
Net Billing Obligations:			
Net Billing Credits	508,618	476,947	610,180
Payments in Lieu of Net Billing[3]	(21,395)	(140,261)	(111,329)
Net Billing Obligations — Cash	487,327	336,686	498,851
Net Billing Expenditures:			
Net Billed Debt Service	222,779	104,329	213,919
Other Entities O&M — Net Billed	221,210	208,535	167,026
Increase/(Decrease) in Prepaid Expense	43,338	23,822	117,906
Net Billing Expenditures — Accrual	$ 487,327	$ 336,686	$ 498,851

(1) Bonneville funds its obligation for Net Billed Project costs on a cash basis and it expenses the Net Billed Project budgets on an accrual basis. This reconciliation ties the cash net billing obligation to the accrual net billing obligation through the changes in Bonneville’s prepaid expense.

(2) Bonneville’s actual revenues from Publicly-Owned Utilities exceeded net billing obligations. Most Publicly-Owned Utilities are Participants in the Net Billed Projects (*i.e.*, Trojan Nuclear Project or Energy Northwest’s Project 1, Project 3 and Columbia Generating Station).

(3) Includes voluntary direct cash payments made to Energy Northwest and/or the Issuer by Bonneville when the related Energy Northwest or Trojan Participants’ obligations to Energy Northwest exceed the allowed net billing credits.. The Trojan and Energy Northwest Net Billing Agreements provide that, under certain circumstances, Bonneville is to reassign a net billing participant’s shares of related projects, if Bonneville anticipates that the billings by Bonneville to the participant are expected to be less than the amounts to be paid by the participant to the Issuer and/or Energy Northwest. Bonneville obviates the need to provide for such reassignments by making voluntary direct cash payments to the Issuer and/or Energy Northwest on the participant’s behalf.

BONNEVILLE LITIGATION

Kaiser Aluminum Bankruptcy

Kaiser Aluminum and Chemical, Incorporated (“Kaiser”), a subsidiary of Kaiser Aluminum Corporation, is one of Bonneville’s aluminum company DSI customers. On February 12, 2002, both Kaiser and its parent corporation Kaiser Aluminum Corporation filed for bankruptcy protection. Bonneville had a contract (the “Kaiser Contract”) to sell Kaiser about 291 megawatts of electric power during the five-year period beginning October 1, 2001. Bonneville estimates that it has sold Kaiser between about $1 million and $2 million of power and related services for which Bonneville has not yet been paid. Such accounts receivable will be treated as unsecured, pre-petition debts of Kaiser in the bankruptcy proceeding and therefore Bonneville is uncertain whether such debts will be paid. Bonneville has recorded provisions for uncollectible amounts related to such accounts receivable.

In addition, Kaiser's purchase obligation under the Kaiser Contract is a "take-or-pay" obligation, meaning Kaiser must pay for the power if tendered by Bonneville, regardless of Kaiser's ability to accept delivery of the power for use at its facilities. Kaiser rejected the Kaiser Contract in the bankruptcy proceeding. The consequence of this rejection is that the "take or pay" obligation that Kaiser owes to Bonneville for future deliveries will be treated as a general unsecured claim.

The United States Department of Justice, acting on behalf of Bonneville, has filed a proof-of-claim in the amount of $78 million in this proceeding, reflecting the value of contracts Bonneville has with Kaiser.

PGET Bankruptcy

In July 2003, PG&E Energy Trading – Power L.P. ("PGET"), a non-utility power marketer and affiliate of PG&E, which in turn is a California utility, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Maryland. As a result, Bonneville has notified PGET that Bonneville has terminated all power sales and purchase transactions with PGET. Bonneville also notified PGET of Bonneville's calculation of a termination payment owed by PGET to Bonneville in the amount of approximately $24 million. On June 8, 2004, PGET and Bonneville executed a settlement agreement in which PGET agreed that it would not dispute a Bonneville claim in the amount of $21.8 million. Apart from relatively small dollar amounts relating to two short term power transactions, undelivered power by PGET, and accounts receivable owing to Bonneville at the time of filing, virtually all of the termination payment calculated by Bonneville is attributable to the mark-to-market value of a single 100 megawatt Augmentation Purchase by Bonneville. At the time of Bonneville's notification of termination, there were approximately three years of remaining performance under the Augmentation Purchase. Bonneville is unable to predict whether or the extent to which it will receive any payment on its undisputed unsecured claim.

Longview Aluminum Bankruptcy

On January 28, 2003, Bonneville notified Longview Aluminum, LLC ("Longview") that Bonneville has terminated Longview's 280 average megawatt take-or-pay power sales contract because of nonpayment by Longview. Bonneville estimates that Longview is approximately $17 million in arrears in its payments under the contract and owes Bonneville approximately $3 million for accounts receivable and about $29 million for the forward value of the contract, which is based on the mark-to-market value of remaining sales as of the date of termination. Longview also has an unpaid $1.2 million payment obligation to Bonneville under a long-term transmission service agreement. In addition, Bonneville has made about $9 million in transmission investments, which Longview would be responsible to pay if it fails to meet its long-term transmission purchase obligation.

In February 2003, Longview Aluminum filed two petitions for review against Bonneville in the Ninth Circuit Court. These petitions have been dismissed with prejudice. On March 4, 2003, Longview filed for bankruptcy protection under the federal bankruptcy laws. Bonneville has filed proofs-of-claim totaling approximately $63 million under power and transmission sales agreements. The Trustee appointed in this case was unsuccessful in his attempts to sell Longview as a going-concern, and has since liquidated virtually all of Longview's assets. Bonneville expects to receive little, if anything, on its unsecured claim.

GNA Bankruptcy

On December 22, 2003, Golden Northwest Aluminum ("GNA"), a holding company that contracts on behalf of two DSIs with Bonneville, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Oregon. Bonneville estimated that GNA owed Bonneville approximately $18 million on an unsecured basis for take-or-pay power purchase commitments in fiscal years 2002 and 2003. Bonneville filed a proof of claim in the case for this amount plus an additional $500,000, approximately, for certain transmission related claims. Bonneville has entered into a settlement agreement with GNA regarding certain post-bankruptcy petition claims and Bonneville has recorded reserves with respect to its unpaid claims in an amount it believes is appropriate.

Mirant Bankruptcy

On July 14, 2003, Mirant Americas Energy Trading, L.P. ("Mirant"), an independent power marketer and power trading counterparty of Bonneville's, filed a petition in the U.S. Bankruptcy Court for the Northern District of Texas. On July 30, 2003, Bonneville sent Mirant a letter terminating certain power purchases by Bonneville. The basis for this termination action was the filing of a bankruptcy petition, which is an event of default that permits the termination and close-out of existing positions between the parties.

Mirant contested Bonneville's right to terminate the contract, claiming that Bonneville was not a forward contract merchant under the U.S Bankruptcy Code, and therefore not entitled to terminate the contract upon filing of the bankruptcy by Mirant. Mirant filed a motion with the bankruptcy court seeking an order that by closing out its position, Bonneville violated the automatic stay provisions of the Bankruptcy Code, which provisions in most circumstances prohibit a party from obtaining recovery of obligations owed to it by the bankrupt without court consent.

The court issued an order on November 14, 2003, directing Bonneville to remedy its violations of the automatic stay by immediately taking all actions necessary to withdraw the termination letter, reinstate the terminated contracts and reinstate the parties to the status quo existing before the termination letter was sent. Thus, the effect of the order was that Bonneville was required to pay Mirant $522,014 that Bonneville was holding as collateral from Mirant. Bonneville made this payment under protest and with a reservation of rights to appeal the decision. Bonneville then filed a motion with the court seeking to have the automatic stay lifted. On December 23, 2003, the court denied the motion and held, among other things, that Bonneville is not a forward contract merchant under the Bankruptcy Code. Bonneville appealed this order in the United States District Court for the Northern District of Texas. The United States District Court for the Northern District of Texas denied Bonneville's appeal on August 13, 2004. The Department of Justice is appealing certain aspects of the court's order in the Fifth Circuit Court. Other possible implications of these rulings are that Bonneville will not enjoy the safe-harbor provisions of the Code afforded to forward contract merchants, and that upon a counter-party's bankruptcy, Bonneville will be precluded by the automatic stay from declaring a default, terminating extant agreements and liquidating all positions, the setoff of pre-petition mutual debts and claims, and to realize against any collateral held to secure the debtor's obligations under the confirmation agreements.

Slice Litigation

On November 17, 2003, a group of Bonneville's Slice customers ("Benton Petitioners") filed a petition with the Ninth Circuit Court challenging Bonneville's final determinations under the Slice Agreements of a Slice true-up adjustment charge, which is an annual adjustment to the Slice Rate. (The true-up charge is described in "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads.") The Benton Petitioners assert that Bonneville's Slice true-up adjustment charge for contract year 2002 is inconsistent with the terms of the Slice contracts and that the Slice customers' audit of fiscal year 2002 charges revealed $83 million in overcharges. The Benton Petitioners further assert that the court lacks jurisdiction to resolve the dispute because the Slice contracts require binding arbitration for such disputes.

On October 23, 2003, a group of Bonneville's full requirements Preference Customers, represented by the Northwest Requirements Utilities ("NRU"), a trade association, filed a petition in the Ninth Circuit Court challenging the same Slice true-up adjustment charge. The NRU Petitioners challenge different aspects of Bonneville's Slice true-up adjustment charge than the Benton Petitioners and are concerned that if the Benton Petitioners were to prevail, the result would be a cost shift to the NRU Petitioners of up to $83 million. In addition, the petition also challenges the Slice customers' assertion that the Slice contract requires the use of binding arbitration as a means to resolve a rate determination of Bonneville under the Northwest Power Act.

The petitions filed by the NRU Petitioners and Benton Petitioners have been consolidated and the cases have been fully briefed.

On March 16, 2004, the NRU Petitioners filed an additional petition for review (NRU II). The reason for the new petition is that Bonneville's determination of the Slice true-up adjustment charge is an annual determination. On December 18, 2003, Bonneville made a final decision regarding its 2003 Slice true-up adjustment charge and billed the Slice customers for 2003 annual true-up adjustment charges. The NRU Petitioners filed for review of the 2003 determination, and asked the court to stay the litigation pending the resolution of NRU I, described above. In April 2004, the Slice customers filed a motion to intervene in NRU II. The court granted the Slice customers' motion to intervene and has stayed the case until June 2005.

2002 Final Power Rates Challenge

Numerous Bonneville customers have filed petitions for review in the Ninth Circuit Court challenging Bonneville's 2002 Final Power Rates Proposal. The rates have been confirmed and approved by FERC. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Strategy Contracts Opt-Out Provisions." Briefing has been completed and the parties await the scheduling of oral argument.

City of Burbank, California v. United States

In 1998, the City of Burbank, California ("Burbank") filed a breach of contract claim against the United States in the Court of Federal Claims. Burbank alleges that Bonneville breached a Power Sales and Exchange Agreement with Burbank by (i) converting the power delivery obligation under the agreement from a power sales mode to a power exchange mode and (ii) improperly calculating the power rate that Burbank is responsible to pay under the agreement. Burbank sought between $3 million and $4 million in damages.

Without motion of any party to the litigation, in July 2000, the Court of Federal Claims dismissed Burbank's action on the grounds that the matter is a dispute over a Bonneville rate and involves actions taken by Bonneville under its governing statutes. It was therefore determined that exclusive jurisdiction lies with the Ninth Circuit Court. In addition, on Bonneville's motion, the court found that Burbank failed to follow certain procedures required under the Contract Disputes Act. Burbank appealed the dismissal to the U.S. Court of Appeals for the Federal Circuit. The Court of Appeals reversed the Court of Federal Claims on the jurisdictional issue and remanded the Contract Disputes Act matter to the Court of Federal Claims.

As part of filing its claim under the Contract Disputes Act, Burbank, as well as the cities of Glendale and Pasadena, submitted certified claims for improperly calculating the applicable power rate under their respective Power Sales and Exchange Agreements. In addition, the City of Burbank submitted a separate claim that alleges that Bonneville improperly converted the agreement from the sale mode to the exchange mode. Burbank's claim for improper calculation of the rate has increased from the original claim to approximately $9 million. The Glendale and Pasadena claims total $4 million and $2 million, respectively.

The claims filed by the cities under the Contract Disputes Act were denied by Bonneville's Contracting Officer, and in April 2003, the cities filed an appeal with the Department of Energy Board of Contract Appeals (the "Board"). In response, Bonneville filed a motion to dismiss for lack of subject matter jurisdiction, and in January 2004 the motion was denied. A hearing on the merits was held before the Board in May 2004. Pursuant to the Board's direction, the parties submitted post-hearing briefs in September 2004.

Residential Exchange Program Litigation

In connection with the implementation of the Subscription Strategy, Bonneville prepared certain *pro forma* Residential Purchase and Sales Agreements ("RPSAs") and tendered the form of such agreements to the Regional IOUs for their consideration and possible execution. The *pro forma* RPSAs proposed to define Bonneville's statutory obligations under the Residential Exchange Program provisions of the Northwest Power Act for the ten-year period beginning October 1, 2001. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line," "—Residential Exchange Program" and "—Power Marketing in the Period After Fiscal Year 2001."

During the same time-frame, Bonneville negotiated certain agreements (the "Residential Exchange Settlement Agreements") with Regional IOUs to settle Bonneville's statutory Residential Exchange Program obligation under such agreements in lieu of the RPSAs for the five- and/or ten-year period beginning October 1, 2001. In October 2000, all six Regional IOUs entered into the Residential Exchange Settlement Agreements in lieu of the RPSAs.

A number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the RPSAs and the Residential Exchange Settlement Agreements and the related records of decisions prepared by Bonneville. A number of interventions have also been filed in the foregoing challenges. Among those participating in the litigation are a group of DSIs, all six Regional IOUs and a number of Preference Customers and Preference Customer groups.

The petitions for review do not specify the precise nature of the challenges to Bonneville's final actions with regard to the RPSAs and the Residential Exchange Settlement Agreements, but allege generally that the RPSAs and Residential Exchange Settlement Agreements violate the Bonneville Project Act, the Pacific Northwest Consumer Power Preference Act, the Transmission System Act, the Northwest Power Act, NEPA, and/or the Administrative Procedure Act. Bonneville expects the likely remedies sought would be that the Residential Exchange Settlement Agreements, and/or RPSAs, be remanded to Bonneville for redevelopment or that Regional IOUs be allowed only to participate in the Residential Exchange Program under the RPSAs.

In June 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements that affect such Regional IOUs' Residential Exchange Settlement Agreements. Among other things, these additional agreements reduce by one half certain payments in the aggregate amount of $200 million that Bonneville otherwise owed to the two subject Regional IOUs in fiscal years 2005 and 2006 under their Residential Exchange Settlement Agreements.

In addition, with respect to the other four Regional IOUs, Bonneville has also entered into agreements having terms similar to those for Puget and PacifiCorp, although the reduction in financial payments that Bonneville will make to such Regional IOUs in the current rate period will be only $3-$4 million in aggregate. For a discussion of the foregoing agreements with the Regional IOUs see "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Residential Exchange Program Obligations."

Several of Bonneville's customers have filed lawsuits in Ninth Circuit Court challenging the June 2004 agreements between Bonneville and the related Regional IOUs.

National Wildlife Federation v. U.S. Army Corps of Engineers

In a lawsuit filed in March 1999, in the United States District Court for the District of Oregon, the National Wildlife Federation ("NWF"), an advocate for environmental causes, has asked the court (1) to find that the Corps has violated state water quality standards for dissolved gas and temperature at four Federal System dams in the lower Snake River and (2) to order the Corps to present to the court a plan for meeting the standards. Plaintiffs seek a court order that would require the Corps to take immediate actions to meet state water quality standards.

Among the measures that plaintiffs assert would reduce gas are a number of capital improvements such as installation of stilling basins and dividers between spillways. Examples of measures to control water temperatures include boring additional channels in a dam so that a dam could pass water from varying depths in the dam's reservoir, and draining reservoirs behind the dams so that the river, although smaller in volume, flows more quickly.

In February 2001, the court issued an opinion and order granting summary judgment in favor of the NWF. The court found that the Corps did not adequately address compliance with its legal obligations under the Clean Water Act in the Corps' 1998 record of decision on dam operations under biological opinions, and supplements thereto, then in effect under the ESA. For a discussion of biological opinions affecting the Federal System hydroelectric projects, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife." The court ordered the Corps to issue a new decision to replace the Corps' 1998 record of decision and to address compliance with the Clean Water Act in the new decision.

In May 2001, the Corps filed a new Record of Consultation and Statement of Decision ("ROCASOD") with the court. As expressed in the ROCASOD, the Corps agreed to consider additional measures in future years to improve water quality. In August 2001, plaintiffs filed an amended complaint challenging the adequacy of the new ROCASOD. Plaintiff's motion included a request for injunctive relief, in addition to a request for remand of the amended ROCASOD to the Corps. The Corps has informed Bonneville that the request for injunctive relief, if successful, could lead to increased funding or program requirements to meet state water quality standards. In November 2002, the district court heard oral arguments on summary judgment motions from plaintiffs and defendants. In January 2003, the court upheld the Corp's ROCASOD and ruled in favor of the Corps on the motions for summary judgment. In March 2003, plaintiffs appealed the court's January ruling upholding the Corps' ROCASOD. A hearing was held before the Ninth Circuit Court in June 2004. In October 2004, the Ninth Circuit Court published an opinion upholding the District Court's affirmation of the Corps' ROCASAD. Plaintiffs subsequently filed a motion seeking review by the entire Ninth Circuit Court panel. In January 2005, the Ninth Circuit Court denied Plaintiff's motion for reconsideration.

Alturas Transmission Dispute

In the mid-1990's Bonneville participated in the interconnection ("Alturas Interconnection") of its federal transmission facilities with facilities owned and operated by Sierra Pacific Power Co. ("Sierra Pacific"). In 1998, Sierra Pacific sought approval from FERC for the Alturas Interconnection, which FERC granted. In late 1998, Sierra Pacific filed at FERC an operating agreement for the interconnection. The Transmission Agency of Northern California ("TANC") and other California public and private utilities intervened in the proceeding, asserting that the interconnection adversely affected reliability of the Pacific Northwest-Southwest AC Intertie, and FERC set the matter for hearing. In March 2001, the Presiding Administrative Law Judge ("ALJ") issued an Initial Decision that supported Bonneville's position that there is no adverse impact on reliability of the Pacific Northwest-Southwest AC Intertie, although the ALJ limited any potential expansion of the Alturas Intertie. Many parties, including Bonneville, appealed the ALJ's decision. Bonneville objected to the limits on expansion, but supported other aspects of the Initial Decision. On August 25, 2003, FERC issued an opinion that modified the Initial Decision by removing the limit on expansion, but affirmed the decision in other respects. TANC and Sacramento Utility District ("SMUD") filed a request for rehearing of the FERC decision and in February 2004 FERC issued an opinion denying rehearing and affirming its August 2003 decision. In April 2004, TANC and SMUD filed an appeal of the FERC decision in Federal appellate court and in May 2004, the United States Department of Justice intervened in the appeal on Bonneville's behalf. On July 29, 2004, TANC and SMUD filed a motion in the D.C. Circuit to dismiss the appeal, effectively ending this litigation.

Southern California Edison v. Bonneville Power Administration

Southern California Edison ("SCE") filed three separate petitions for review against Bonneville in the Ninth Circuit Court. The cases all challenge actions taken by Bonneville regarding the implementation of a 1988 power sale contract ("Sale and Exchange Agreement") between Bonneville and SCE.

In the first petition for review, SCE challenged Bonneville's decision to convert the contract from a sale of power to an exchange of power as provided for under the terms of the contract. In the second petition for review, SCE challenged a Record of Decision issued by Bonneville in a rate adjustment proceeding. That proceeding (FPS-96R) amended Bonneville's FPS-96 rate schedule to establish a posted rate for a capacity product SCE may purchase as part of an option feature of the Sale and Exchange Agreement. SCE alleges that the rate adjustment violates its power sales contract. In the third petition for review, SCE challenged Bonneville's letter to Southern terminating service under its power sales contract due to SCE's nonperformance. All three petitions for review were dismissed by the Ninth Circuit Court for lack of jurisdiction and were transferred to the U.S. Court of Federal Claims. Subsequently, SCE voluntarily dismissed the claims at the U.S. Court of Federal Claims and filed administrative claims for relief with Bonneville.

The current status of the claims is as follows:

> **Conversion from Sale to Exchange Mode**. Rather than await a Contracting Officer's Decision, SCE filed an action in the Court of Federal Claims on December 26, 2002, based on its assertion that the claim should be "deemed denied" by Bonneville. SCE's complaint seeks damages in the amount of approximately $186,000,000. Bonneville filed a motion to dismiss for failure to state a claim for which relief can be granted. On October 24, 2003 the motion was denied.
>
> **Challenge to FPS-96R.** Bonneville notified SCE that the claim was a challenge to Bonneville's rates, and such challenges are cognizable only in the Ninth Circuit Court of Appeals. On December 30, 2003, SCE filed a complaint in the Court of Federal Claims. SCE's complaint seeks damages in the amount of $32,000,000. In November 2004, Bonneville filed a motion to dismiss the complaint for lack of subject matter jurisdiction.
>
> **Termination for Default.** In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. In August of 2003, SCE filed an administrative claim with Bonneville under the Contract Disputes Act for wrongful termination in the amount of $22,000,000. Bonneville refused to entertain the administrative claim, citing the one-year statute of limitations for challenging a final contracting officer's decision. Subsequently, SCE filed a complaint in November 2004 seeking $22,000,000 in termination for convenience damages. Bonneville intends to file a motion to dismiss for lack of subject matter jurisdiction.

Industrial Customers of Northwest Utilities, et al. v. Bonneville Power Administration

Three petitions for review were filed in the Ninth Circuit Court challenging Bonneville's February 2003 determination that the criteria for triggering a Safety Net Cost Recovery Clause ("SN-CRAC") had been satisfied. The consequence of triggering the SN-CRAC was to initiate a proceeding to revise Bonneville's rates. The three petitions were filed by an entity representing industrial customers of Northwest utilities, by Alcoa, Inc. (a DSI), and by some of Bonneville's Preference Customers. Numerous other parties have moved to intervene. On June 12, 2003, the court consolidated all three petitions for review. On August 15, 2003, Bonneville filed a motion to dismiss these cases for lack of jurisdiction, or in the alternative, to stay the cases pending completion of an administrative review process at FERC. Bonneville's motion was referred to the merits panel, and briefs on the merits have been filed.

Fiscal Year 2004 SN-CRAC Adjustment Litigation

In June through August of 2004, petitioners Public Power Council, a number of DSIs, the Canby Utility Board, and the Industrial Customers of Northwest Utilities ("Petitioners") filed petitions for review in the Ninth Circuit Court. Petitioners challenge Bonneville's establishment of the SN-CRAC as confirmed and approved by FERC, and seek to have the SN-CRAC declared invalid by the court. The parties are in the process of preparing briefs.

Yakama Nation Litigation

On June 24, 2003, the Yakama Nation, a tribal entity, filed a petition for review in the Ninth Circuit Court challenging a letter issued by Bonneville dated March 28, 2003. The letter addresses Bonneville's funding of measures in the

Northwest Power and Conservation Council's Fish and Wildlife Program. The petition does not provide any information regarding the Yakama Nation's legal theories and includes no request for expedited review or injunctive relief. The case has been selected for inclusion in the Ninth Circuit Court's mediation program and has been stayed pending settlement discussions.

Upper Columbia United Tribes Litigation

On December 18, 2003, the Upper Columbia United Tribes ("UCUT"), as well as certain other tribal petitioners, filed a petition for review in the Ninth Circuit Court challenging a letter from Bonneville to the Council. As with the Yakama Nation Litigation, above, the challenged letter addresses issues related to Bonneville's Fish and Wildlife Funding. The UCUT litigation is related to the Yakama Nation litigation, described above, and has been selected for inclusion in the Ninth Circuit Court's mediation program. Bonneville and the UCUT petitioners are currently engaged in settlement discussions, and the case is stayed pending such discussions.

ESA Litigation

National Wildlife Federation v. National Marine Fisheries Service

In a lawsuit filed May 4, 2001, in the United States District Court for the District of Oregon, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Biological Opinion and incidental take statement are arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NMFS (now known as "NOAA Fisheries") to reinitiate consultation with the action agencies responsible for operation of the Federal System hydroelectric projects—the Corps, the Bureau, and Bonneville (collectively, the "Action Agencies")—and to prepare a new biological opinion. Plaintiffs subsequently filed a first amended complaint, and the action agencies filed their answer. Several entities have intervened in this lawsuit. The court heard oral argument on motions for summary judgment in April 2003.

In early May 2003, the U.S. District Court judge issued a decision on the adequacy of the 2000 Biological Opinion. The ruling provides that the 2000 Biological Opinion is inadequate because it relies on offsite mitigation measures that are "not reasonably certain to occur."

In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court.

On November 30, 2004, NOAA Fisheries finalized a new biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court. For a discussion of the 2004 Biological Opinion, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—2000 and 2004 Biological Opinions."

Plaintiffs have filed a complaint against NOAA Fisheries with the District Court, alleging that the 2004 Biological Opinion violates certain provisions of the ESA. Additionally, Plaintiffs and the State of Oregon have filed a 60 Day Notice of Intent to Sue, as required by the ESA, against the Action Agencies.

Alsea Valley Alliance v. Evans

In September 2001, the United States District Court for the District of Oregon issued an order finding that NMFS (now known as "NOAA Fisheries") had exceeded its authority by listing only the wild-salmon portion of the Oregon Coast Coho salmon as endangered or threatened. The court found that because NOAA Fisheries did not include the entire "distinct population segment" which also includes hatchery fish, it acted arbitrarily and capriciously. As a result, the court de-listed the Oregon Coast Coho salmon as endangered or threatened.

After this decision, a number of intervener environmental groups appealed the decision to the Ninth Circuit Court. These groups successfully stayed the findings of the district court. The effect of the stay was to temporarily re-list the Oregon Coast Coho pending the decision on appeal. In addition to the appeal, NOAA Fisheries received 14 additional petitions from various interest groups to de-list other salmon populations. As a result, NOAA Fisheries decided to revisit its Hatchery Listing Policy.

In February 2004, the Ninth Circuit Court rejected the intervener environmental groups' motion to reinstate the Oregon Coast Coho as a listed species and upheld the District Court's invalidation of the listing decision. Thus, the Oregon Coast Coho was de-listed under the ESA. In June 2004, NOAA Fisheries published a proposed new hatchery policy and a proposed rule for the listing of 25 salmon and salmon-related populations, all but one of which had previously been listed. The proposed rule would re-list the Oregon Coast Coho salmon and would list the Lower Columbia Coho salmon for the first time. The other 23 populations would remain listed as either endangered or threatened, representing no change from current status. NOAA Fisheries must make a final decision on a proposed listing rule by June 14, 2005, and it has stated that it expects to issue a final hatchery policy shortly prior to that date.

Spill Reduction Litigation

In February 2004, two environmental groups delivered a formal "intent to sue" notice to Bonneville, the Corps and the Bureau. The notice, a prerequisite to filing suit under the ESA, was in response to Bonneville's proposal for a reduction in the amount of water spilled over four Federal System dam spillways in July and August of 2004 and consequent increase in electric power generation. The notice indicated that the environmental groups would file suit against the above listed Federal agencies unless alleged ESA violations relating to reduced summer spill were cured. In June 2004, the Federal agencies involved agreed to proceed with the spill reduction proposal. Bonneville anticipated that the spill reduction proposal would have enhanced fiscal year 2004 power revenues by $20 million to $40 million. The two environmental groups and others (the "Petitioners") then filed an emergency motion for injunctive relief with the United States District Court for the District of Oregon, the court presiding over the National Wildlife Federation v. National Marine Fisheries Service litigation described above. In July 2004, the court ruled in favor of the Petitioners and enjoined the spill reduction proposal from being implemented. The Federal agencies subsequently filed an appeal in Federal appellate court seeking to overturn the injunction. In August 2004, the appellate court denied the Federal agencies' appeal, effectively ending the litigation. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2004 Developments—Bonneville's Unaudited Fiscal Year 2004 Third Quarter Results and Fiscal Year-End Forecast as of June 30, 2004."

Rates Litigation

Bonneville's rates are frequently the subject of litigation. Most of the litigation involves claims that Bonneville's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record or are arbitrary and capricious. Bonneville proposed new power rates for the five years beginning October 1, 2001, which were subsequently approved by FERC in July 2003. Bonneville also proposed an SN-CRAC rate level adjustment, which was reviewed and approved by FERC. Bonneville has proposed transmission rates for the two years beginning October 1, 2003. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001," "TRANSMISSION BUSINESS LINE—Bonneville's Transmission and Ancillary Service Rates" and "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates."

It is the opinion of Bonneville's General Counsel that if any rate were to be rejected, the sole remedy accorded would be a remand to Bonneville to establish a new rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville is unable to predict, however, what new rate it would establish if a rate were rejected. If Bonneville were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid. However, Bonneville is required by law to set rates to meet all of its costs; provided, however, that in the case of a FERC-ordered transmission rate no such rate shall be unjust, unreasonable or unduly discriminatory. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Miscellaneous Litigation

From time to time, Bonneville is involved in numerous other cases and arbitration proceedings, including land, contract, employment, federal procurement and tort claims, some of which could result in money judgments or increased costs to Bonneville. The combined amount of damages claimed in these unrelated actions is not expected to exceed $50 million.

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

Financial Statements

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 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 Changes in Capitalization and Long-Term Liabilities

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

	Accumulated Net (Expenses) Revenues	Federal Appropriations	Bonds Issued to Treasury	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 bonds issued to U.S. Treasury	—	—	470,000	—	—	470,000
Repayment of bonds issued to U.S. Treasury	—	—	(482,687)	—	—	(482,687)
Refinance of bonds issued to U.S. Treasury	—	—	(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 bonds issued to U.S. Treasury	—	—	**480,000**	—	—	**480,000**
Repayment of bonds issued to U.S. Treasury	—	—	**(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 FB 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

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.

$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 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

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

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 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

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

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 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 p urchased 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. Bonds issued to U.S. Treasury

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 bonds issued to U.S. Treasury, 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 bonds issued to U.S. Treasury.

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 $248 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

Bonds issued to U.S. Treasury

Long-Term Debt— 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

The weighted average interest rate was 4.9 percent on outstanding bonds issued to U.S. Treasury as of Sept. 30, 2004. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

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.

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

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

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**
Net operating revenues	**481,787**	**125,621**	**181,858**	**—**	**789,266**
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
Net operating revenues	419,591	166,224	315,200	—	901,015
Interest expense	176,595	168,996	—	—	345,591
Net revenues (expenses)	$ 242,996	$ (2,772)	$ 315,200	$ —	$ 555,424
2002					
Unaffiliated revenues	$ 2,967,074	$ 566,655	$ —	$ —	$ 3,533,729
Intersegment revenues	80,729	153,727	—	(234,456)	—
Total operating revenues	3,047,803	720,382	—	(234,456)	3,533,729
Unaffiliated expenses	2,605,847	283,809	(52,907)	—	2,836,749
Depreciation	174,164	161,041	—	—	335,205
Intersegment expenses	153,630	80,729	97	(234,456)	—
Total operating expenses	2,933,641	525,579	(52,810)	(234,456)	3,171,954
Net operating revenues	114,162	194,803	52,810	—	361,775
Interest expense	201,582	150,718	—	—	352,300
Net revenues (expenses)	$ (87,420)	$ 44,085	$ 52,810	$ —	$ 9,475

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%

Federal Columbia River Power System

Consolidated Balance Sheets (Unaudited)

(thousands of dollars)

Assets

	December 31 2004	December 31 2003
Utility Plant		
Completed plant	$ 12,307,560	$ 12,016,909
Accumulated depreciation	(4,418,885)	(4,343,015)
	7,888,675	7,673,894
Construction work in progress	1,396,342	1,359,880
Net utility plant	9,285,017	9,033,774
Nonfederal Projects		
Conservation	40,437	43,761
Hydro	146,210	146,210
Nuclear	2,221,561	2,181,405
Terminated hydro facilities	27,305	28,090
Terminated nuclear facilities	3,896,566	3,885,752
Total nonfederal projects	6,332,079	6,285,218
Decommissioning Cost	164,000	123,788
IOU exchange benefits	606,539	–
Conservation, net of accumulated amortization	328,938	369,724
Fish & Wildlife, net of accumulated amortization	116,913	122,526
Current Assets		
Cash	809,307	692,066
Accounts receivable, net of allowance	111,608	107,741
Accrued unbilled revenues	226,172	261,344
Materials and supplies, at average cost	82,008	84,063
Prepaid expenses	283,864	214,005
IOU exchange benefits	286,290	–
Total current assets	1,799,249	1,359,219
Other Assets	343,822	230,636
	$ 18,976,557	$ 17,524,885

Capitalization and Liabilities

	2004	2003
Capitalization and Long-Term Liabilities		
Accumulated Net Revenues	$ 956,921	$ 513,533
Federal Appropriations	4,347,741	4,615,558
Capitalization Adjustment	2,039,905	2,107,800
Bonds issued to U.S. Treasury	2,426,800	2,521,554
Nonfederal Projects Debt	6,212,972	6,044,877
Decommissioning Reserve	164,000	123,788
IOU exchange benefits	626,676	49,456
Accrued plant removal costs	107,527	96,600
Total capitalization and long-term liabilities	16,882,542	16,073,166
Current Liabilities		
Current portion of federal appropriations	104,673	73,484
Current portion of bonds issued to U.S. Treasury	528,500	176,200
Current portion of nonfederal projects debt	238,693	240,341
Current portion of IOU exchange benefits	286,290	–
Accounts payable and other current liabilities	379,241	401,968
Total current liabilities	1,537,397	891,993
Deferred Credits	556,618	559,726
	$ 18,976,557	$ 17,524,885

Federal Columbia River Power System

Consolidated Statements of Revenues and Expenses (Unaudited)

(thousands of dollars)

	Three months ended December 31		Twelve months ended December 31	
	2004	2003	**2004**	2003
Operating Revenues				
Revenues	**$ 747,551**	$ 736,129	**$ 2,984,918**	$ 3,244,187
SFAS 133 mark-to-market (loss) gain	**(8,826)**	(1,210)	**81,836**	6,921
Other revenues	**11,916**	13,994	**55,885**	57,643
U.S. Treasury credits for fish	**17,338**	19,654	**74,684**	179,542
Total operating revenues	**767,979**	768,567	**3,197,323**	3,488,293
Operating Expenses				
Operations and maintenance	**279,879**	226,477	**1,265,204**	1,161,311
Purchased power	**133,304**	144,595	**570,838**	946,814
Non-Federal projects	**83,987**	64,322	**268,140**	128,652
Federal projects depreciation	**89,845**	88,836	**367,248**	353,767
Total operating expenses	**587,015**	524,230	**2,471,430**	2,590,544
Net operating revenues	**180,964**	244,337	**725,893**	897,749
Interest Expense				
Interest on federal investment				
Appropriated funds	**49,084**	52,068	**210,057**	209,954
Bonds issued to U.S. Treasury	**29,005**	30,331	**108,925**	156,682
Allowance for funds used during construction	**(6,598)**	(7,823)	**(37,216)**	(34,182)
Net interest expense	**71,491**	74,576	**281,766**	332,454
Net Revenues	**$ 109,473**	$ 169,761	**$ 444,127**	$ 565,295

Derivative Instruments and Hedging Activities

The SFAS 133 mark-to-market (MTM) amount is an "accounting only" (no cash impact) adjustment representing the MTM adjustment required by SFAS 133, as amended, for identified derivative instruments.

APPENDIX C

EUGENE WATER & ELECTRIC BOARD AND ITS ELECTRIC SYSTEM

Service Area

The Electric System provides electricity to a 238-square mile area, including the City and adjacent suburban areas, and areas near the Walterville, Leaburg and Carmen-Smith hydroelectric plants. The Board's service area in and around the City adjoins the City of Springfield's system on the east, the Emerald People's Utility District's system and the Blachly-Lane County Electric Cooperative's system, both on the west, and Lane Electric Cooperative's system on the south. The Board also provides service to Weyerhaeuser Company's operation within the Springfield city boundary.

Rates

The Board has, by City Charter and Oregon law, exclusive jurisdiction to fix rates for electric service within its service area. Information regarding covenants of the Board with respect to electric rates is set forth under the heading "SECURITY FOR THE BONDS — General; Flow of Funds; The Net Billing Agreements; Bond Resolution Rate Covenant" herein. Under Oregon law (ORS 225.210 to 225.300), and as part of its annual planning and budgeting process, the Board examines the cost of providing electric service to determine that rates are sufficient to fund all operating costs and expenses, repairs, replacements, debt service and capital additions to the Electric System. If there appears to be a need to adjust rates, a formal cost of service study is performed. The primary cornerstone of the cost of service study is to establish rates that, to the maximum extent feasible, do not include cross-subsidies among rate classes. At the end of the study, staff develops a rate proposal. The Board then holds two public hearings to gather public comment on the rate proposal. Once the public comments have been considered, the Board may modify or adopt the new rates.

In November 2001, the Board adopted two rate adjustment mechanisms to allow interim rate changes through a process that is less formal than the process described above. The first is a Power Cost Recovery Adjustment. This involves a retrospective comparison of planned and actual net power costs for the prior year. If there is a significant variation in net power costs, the Board may surcharge or credit future bills to recover the difference. The second rate adjustment mechanism is a Bonneville Power Cost Recovery Adjustment. This involves a comparison of the Bonneville costs for the upcoming six months to the Bonneville costs included in current rates (Bonneville has the ability to adjust its rates to the Board every six months). If there is a significant difference, the Board may adjust rates to reflect the expected Bonneville costs for the upcoming six month period. After its most recent review, the Board reduced its retail rates by 1.6% effective in May, 2005.

The following is a summary of the Board's rate changes over the last 5 years:

Effective Date	Percentage
April 2000	6.2%
April 2001	5.4
November 2001	32.8
May 2002	2.9
May 2004	4.6
November 2004	5.7

The average annual usage for the Electric System's residential customers in 2004 was 12,721 kWh. The Board's 2004 average rate per kWh for residential service was 7.44 cents. The Board's 2004 average rate for commercial and industrial service was 5.98 cents per kWh. The Board believes that its industrial and general service rates are comparable to and competitive with market alternatives available in the region and nationally.

Customer Sales and Revenues

The following table shows the average number of retail customers, sales in kWh, revenues from retail customer sales, and system peak loads experienced by the Electric System during the period 2000-2004:

Year	Number of Retail Customers	Sales kWh (000)	Revenues	System Peak Load (kW) (1)
2000	80,114	2,844,528	$112,611,513	537,000
2001	79,400	2,671,516	124,076,564	565,000
2002	81,575	2,542,729	150,285,004	506,700
2003	82,294	2,542,158	150,526,729	498,000
2004	83,118	2,634,133	161,031,431	542,000

(1) A substantial portion of system peak load is attributed to electric heating and therefore peak load in any given year is a function of weather.

Largest Customers

EWEB's five largest retail customers accounted for 21.7% of sales and 32.0% of revenues of the Electric System in 2004. EWEB has modeled the hypothetical loss of loads from its largest customers, and the impact of the loss of any one of its large customers would be an average retail rate increase of less than 2 percent. The following table shows the respective loads and revenues for the five largest customers of EWEB during 2004:

Customer	Revenues	% of Revenues	Sales kWh	% of Retail Sales
Weyerhaeuser Companies	$ 18,896,962	11.7%	504,379,717	19.1%
Hynix Semiconductors	9,006,253	5.6	199,140,808	7.6
University of Oregon	3,043,927	1.9	59,494,389	2.3
Peace Health	2,116,199	1.3	39,813,759	1.5
Sierra Pine	1,837,000	1.1	41,230,440	1.6
All Other Retail	126,131,090	78.3	1,790,073,887	68.0
Total	$160,031,431	100.0	2,634,133,000	100.0

The Board's retail service contract with Sierra Pine terminated as of February 1, 2005. EWEB has executed an amended retail service contract with Weyerhaeuser Company which expires on September 30, 2011.

Historical Electric System Operating Results

The following table summarizes the operations of the Electric System during the period 2000 through 2004:

	2000	2001	2002	2003*	2004
Average number of customers	80,114	79,400	81,525	82,294	83,118
Operating ratio(1)	83.2	1.01	80.0	80.8	74.6
Average retail rate increases(2)	6.2%	5.4/32.8%	2.9%	None	4.6/5.7%
Average annual consumption per residential customer (kWh)	14,746	13,599	13,157	12,645	12,721
Average annual residential revenue per customer	$695	$744	$920	$891	$947
Average residential revenue (cents per kWh)	4.7	5.5	7.0	7.0	7.44
Revenues(3)	$209,353,391	$357,612,026	$213,096,765	$214,174,075	$215,176,725
Commercial Paper Program Proceeds	-0-	25,000,000	5,000,000	-0-	-0-
Expenses(4)	(174,259,551)	(362,142,824)	(170,478,015)	(171,934,577)	(160,599,762)
Amount available for Electric System Debt Service	$35,093,840	$20,469,202	$47,618,750	$41,081,725	$54,576,963
Megawatt hour sales (000)(5)	3,041	2,672	2,543	2,543	2,634

(1) Operating ratio is calculated by dividing operating expenses, as specified below, by operating revenue.
(2) In 2001, the Board had two rate increases for retail (5.4% in May and 32.8% in November). In 2004, the Board has two rate increases for retail (4.6% in May and 5.7% in November).
(3) Operating revenue includes interest income on unrestricted funds and other revenue.
(4) Operating expenses and other reductions, excludes depreciation and amortization of conservation assets.
(5) Represents retail sales only.
* 2003 was reclassified due the Emerging Issues Task Force No. 03-11 (EITF 03-11), Reporting Realized Gains and Losses on Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes.

The audited financial statements of the Board for 2004 are contained in Appendix D. Following is an unaudited statement of the operating results of the Electric System for the years ended December 31, 2004 and December 31, 2003:

Electric System
Statement of Revenues, Expenses and Net Assets
for the years ended December 31, 2004 and December 31, 2003

	2004	2003
Residential	$ 70,407,141	$ 65,572,237
Commercial and industrial	93,571,025	87,652,063
Sales for resale and other	47,100,177	56,344,640
Operating Revenues	211,078,343	209,568,940
Purchased power	102,049,042	113,319,969
System control	4,049,527	3,775,859
Wheeling	9,983,934	13,011,389
Steam and hydraulic generation	9,983,462	9,674,398
Transmission and distribution	13,506,069	11,095,746
Source of supply, pumping and purification	-	-
Customer accounting	7,081,874	6,190,618
Conservation expenses	1,499,279	1,410,185
Administrative and general	12,220,875	12,838,658
Depreciation on utility plant	10,946,247	10,089,090
Operating Expenses	171,320,309	181,405,912
Net Operating Revenue (Loss)	39,758,034	28,163,028
Interest and investment revenue	1,901,818	2,054,890
Allowance for funds used during construction	333,944	265,799
Other revenue	2,355,375	2,941,604
Other Revenues	4,591,137	5,262,293
Contributions in lieu of taxes	10,466,872	9,866,496
Other revenue deductions	4,102,553	4,654,375
Interest expense and related amortization	11,283,547	10,529,883
Allowance for borrowed funds used during construction	(478,659)	(463,662)
Other Expenses	25,374,313	24,587,092
Income before contributed capital	18,974,858	8,838,229
Contributed capital	2,815,070	2,411,697
Change in net assets	21,789,928	11,249,926
Total net assets at beginning of year	120,095,178	108,845,252
Total net assets at end of year	$141,885,106	$120,095,178

Power Supply—General

Approximately 17 percent of the electric power requirements of the Electric System to meet load come from the Board's generation capacity, 77 percent is purchased from Bonneville and 6 percent is purchased from other suppliers. The Board, which is a statutory preference customer of Bonneville, purchases its Slice and Block power products. See Appendix A, "BONNEVILLE POWER ADMINISTRATION — POWER BUSINESS LINE — Certain Statutes And Other Matters Affecting Bonneville Power Business Line — Power Marketing In The Period After Fiscal Year 2001" for a discussion of Bonneville's Slice and Block Programs.

The following table contains a summary of the electric generating resources currently available to the Board based on median and critical (minimum) stream flows for hydroelectric facilities. A discussion of each of the resources follows.

Board Owned and Contracted Resources for Calendar Year 2004

	January Sustained Peaking Capability (MW)	2004 Generation (MWh)
EWEB Owned Resources		
Carmen-Smith and Trailbridge Hydroelectric Plants	44.0	251,100
Leaburg Hydroelectric Plant	13.0	107,000
Waterville Hydroelectric Plant	9.0	75,000
Stone Creek Hydroelectric Plant	10.0	67,000
Weyerhaeuser Industrial Cogeneration Project[a]	13.5	64,000
Foote Creek (WY) Wind Project	0.0	20,000
Smith Creek Hydro Project	0.0	82,000
Subtotal	89.5	660,000
Contract Resources		
Priest Rapids and Wanapum Hydroelectric Contract	30.0	149,000
Stateline	7.0	62,000
Foote Creek I	2.0	18,000
Subtotal	39.0	229,000
System Purchases		
Bonneville Base Slice Product	250.0	2,033,000
Bonneville Block Product	100.0	624,000
Bonneville Surplus Firm	25.0	219,000
Subtotal	375.0	2,876,000
TOTAL	503.5	3,765,000

[a] This is the Board's half-share of the project output. The other half is used by Weyerhaeuser. See additional discussion below.

Board-Owned Resources

Carmen-Smith Hydroelectric Project. The Board owns and operates the Carmen-Smith Hydroelectric Project ("C-S Project") within the McKenzie River basin. The C-S Project includes two generating units with a nameplate capacity of 55 MW each. The C-S Project also includes the Trailbridge re-regulating facility, which includes an additional generating unit with a nameplate capacity of 10 MW.

The current FERC license for the C-S Project expires in 2008. The Board has submitted to FERC its notice of intent to apply for a new license for the C-S Project, and is currently undertaking the necessary actions to apply for and secure a new license.

Leaburg-Walterville Hydroelectric Project. The Board also owns and operates the Leaburg-Walterville Hydroelectric Project ("L-W Project") on the McKenzie River in Lane County, Oregon. The L-W Project is comprised of two facilities located at different points on the McKenzie River. The

Leaburg facility includes a diversion dam on the McKenzie River, a canal and two generating units with a combined nameplate capacity of 15.5 MW. The Walterville facility includes a canal that diverts water from the McKenzie River and one generating unit with a nameplate capacity of 9 MW. In 2001, FERC granted the Board a new hydroelectric license for the L-W Project. The new license is for a term of 40 years.

Stone Creek Project. The Stone Creek project has one turbine with a peak capability of 12 MW. The project is a run-of-river development located between two hydroelectric facilities that are owned and operated by PGE. It was completed in 1993 by an independent power producer, and the Board purchased the project in 1994. The facility is operated and maintained under contract with PGE, and is licensed through 2038. The facilities are on the Clackamas River approximately 45 miles southeast of Portland.

Weyerhaeuser Industrial Energy Center Cogeneration Project. The Board and the Weyerhaeuser Company cooperatively developed a cogeneration facility at the Weyerhaeuser Springfield plant in 1976. The unit, which has a nameplate capacity of 51.2 MW (average output is approximately 20 aMW), is owned by the Board, with Weyerhaeuser providing operation and fuel. Under terms of the current agreement (which expires in 2015), the project costs and output for this unit are shared equally by the parties. In addition to the unit, there are three other turbines (with a total capacity of 25 MW and owned by Weyerhaeuser) at the plant. Although output and operating costs for these units are also shared by Weyerhaeuser and the Board, they do not normally operate due to high running costs.

Smith Creek Hydro Project. The Smith Creek project is a run-of-the-river hydroelectric project on Smith Creek, a tributary of the Kootenai River in Northern Idaho. It is comprised of three units with a combined nameplate capacity of 36 MW. In April 2001, the Board took ownership of the project, which is licensed through 2037.

Foote Creek I Wind Project. As a result of surveys showing customer interest in paying premium prices for energy produced from environmentally-friendly projects, the Board partnered with PacifiCorp to develop the Foote Creek I Wind Project, and instituted a retail marketing program to accompany it. The project was constructed along the Foote Creek Rim in Carbon County, Wyoming, which is considered to be one of the premier wind energy development sites in the United States, with an average annual wind speed of approximately 24 miles per hour. The 41.4 MW project includes 69 turbine-wind machines, a new substation and over 28 miles of transmission line to connect to the existing transmission system in the area. The Board and PacifiCorp are the joint owners of the project, with the Board having a 21.21% percent ownership, which translates to 8.8 MW of the project capacity. Of this capacity, 26% is sold to Bonneville under terms of a 25-year power purchase agreement, pursuant to which Bonneville has committed to purchase 15.3 MW of the Project's total capacity, of which 2.3 MW are from the Board. Net of sales to Bonneville, the Board receives approximately 2.5 average MW (or 22,000,000 kWh) per year from the Foote Creek I Project.

As the Board unbundled its rates into energy and transmission components, separate rate classes were established to allow customers to voluntarily subscribe at several different levels of participation in windpower. Options are currently available where windpower will comprise 0, 10, 25, 50, or 100 percent of the energy portion of a customer's bill. Large commercial and industrial customers have the option to buy 1,000 kW blocks of windpower energy for an additional cost of $14 per block. Because of recent rate increases, the windpower rate approximates the average retail rate.

Contract Resources

Priest Rapids and Wanapum Hydroelectric Projects. The Board has entered into agreements with Public Utility District No. 2 of Grant County, Washington ("Grant County PUD") for the purchase of power from the Priest Rapids Development and the Wanapum Development, two large hydroelectric projects on the Columbia River in Washington. In 1956, the Board signed an agreement to purchase 1.7 percent of the output of the Priest Rapids Development. In 1959, the Board signed an agreement to purchase 2.3 percent of the output of the Wanapum Development. Together, the two projects currently provide the Board with a peak capability of 36 MW and about 150 million kilowatt hours of energy annually. The contract for Priest Rapids expires on October 31, 2005 and for Wanapum on October 31, 2009. The Priest Rapids and Wanapum participants, including the Board, have signed new contracts with Grant County PUD to become effective when the existing contracts expire.

Stateline Wind Project. In 2002, the Board agreed to purchase 25 MW from Phase 1 of the Stateline Wind Project located in Walla Walla County, Washington and Umatilla County, Oregon. Phase 1 was completed in late 2001 with a total installed capacity of approximately 300 MW. The project was developed by FPL Energy who retains ownership and sells all output directly to PPM Energy.

System Purchases

Bonneville Priority Firm Purchase Contract. Pursuant to the Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96 501) (the "Regional Power Act"), the Board executed with Bonneville a power sales and purchase contract for the purchase of power equal to its full federal entitlement running from October 1, 2001 through September 30, 2011. The amount is equal to approximately two thirds of the Board's current retail load. The Board selected a combination of both "Block" and "Slice of System" power products from those offered by Bonneville. Each component provides attributes that add different kinds of flexibility to the Board's power portfolio. The "Block" component provides some risk mitigation with respect to a series of poor water conditions while the "Slice" product has attractive extra generation advantages in years that exceed critical water levels. See Appendix A to this Official Statement for information regarding Bonneville's Block and Slice Products.

The Board has purchased a 2.3% Slice share. The annual share is to remain fixed and will not be adjusted to reflect increases or decreases in a customer's net requirements or individual resources during the term of the contract. The customer's percentage share also will not be adjusted to reflect increases or decreases in the output of the Slice System. Actual power received under the Slice Product contract will vary with the performance of the federal based system. In years of heavy water flow, Slice Product customers will have rights to power that may be in excess of their needs, and in poor water years Slice Product customers would need to augment their share of Slice output with their own generation or market purchases.

The Board is a participant to the ongoing Slice Litigation described in Appendix A — "BONNEVILLE POWER ADMINISTRATION" under the heading "Bonneville Litigation—Slice Litigation". Without adopting Bonneville's characterization or description of the Slice Litigation, the Board states that it is one of the Benton Petitioners. As one of the Benton Petitioners, no other party to the Slice Litigation is seeking to recover or impose monetary damages against the Board. An outcome of the Slice Litigation adverse to the Board would mean only that the Board would be unable to recover certain moneys that it has already paid out. Such payments are reflected in the Board's most current audited financial statements.

For a discussion of Bonneville's rates, see Appendix A — "BONNEVILLE POWER ADMINISTRATION—Subscription Strategy, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments".

Bonneville Pre Subscription Contract. The Board has executed an additional pre subscription purchase agreement with Bonneville for a 25 MW block of power. This contract runs from June 1, 2001 through September 30, 2006.

Bonneville NT Transmission Contract. In 2001, the Board signed the Network Integration Transmission Service ("NT") contract with Bonneville to provide transmission for the Board's generation projects and BPA power contracts. The NT contract expires December 31, 2006, but has provision for extensions. The Board has signed an additional Network Transmission Contract with Bonneville that serves the balance of the Electric System's retail load requirement.

Market Purchases

Since the Board entered into a contract with Bonneville in 2001, the Board's combination of generation and long term power supply contracts has been sufficient to meet the Electric System's load requirements on an annual basis. The Board purchases and sells electricity on a daily, weekly, monthly, and seasonal basis to balance resources and load. In addition, the Board purchases put and call options to hedge its risk around wholesale price movements.

Energy Northwest Net Billing Agreement

The Board, Energy Northwest (formerly known as the Washington Public Power Supply System or "WPPSS") and Bonneville entered into a net billing agreement with respect to Energy Northwest's Project No. 1, under which the Board purchased from Energy Northwest, and in turn assigned to Bonneville, 0.061 percent of the capability of Energy Northwest's Project No. 1. The Board is not a participant in any other Energy Northwest projects. Construction of Project No. 1 was terminated in 1994. Under the net billing agreement, Bonneville is responsible for the Board's percentage share of the total annual cost of Project No. 1, including debt service on revenue bonds issued to finance the cost of construction of Project No. 1. Notwithstanding the assignment of the Board's share of the capability of Project No. 1 to Bonneville, the Board remains unconditionally obligated to pay to Energy Northwest its share of the total annual cost of Project No. 1 to the extent payments or credits relating to such annual cost are not received from Bonneville. Under the net billing agreement, payment by Bonneville of the Board's percentage share of the total annual cost of Project No. 1 is made by a crediting arrangement whereby Bonneville credits against amounts which the Board owes Bonneville for the purchase of wholesale power, the Board's share of the total annual cost of Project No. 1. To the extent the Board's share of such annual cost exceeds amounts owed by the Board to Bonneville, Bonneville is obligated, after certain assignment procedures, to pay the amount of such excess directly to the Board or to Energy Northwest from funds legally available therefor.

APPENDIX D

FINANCIAL STATEMENTS OF EUGENE WATER AND ELECTRIC BOARD

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Eugene Water & Electric Board

Annual Report
December 31, 2004 and 2003
(Restated)

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Board of Commissioners
500 East Fourth Avenue
Eugene, Oregon 97401

Mr. Patrick Lanning	President
Ms. Sandra Bishop	Vice-President
Mr. Ron Farmer	Member
Mr. Dorothy Anderson	Member
Mr. Mel Menegat	Member

Officers
500 East Fourth Avenue
Eugene, Oregon 97401

Mr. Randy L. Berggren	General Manager, Secretary
Ms. Krista K. Hince	Assistant Secretary
Mr. James H. Origliosso	Treasurer
Ms. Catherine D. Bloom	Assistant Treasurer

Eugene Water & Electric Board
Index
December 31, 2004

Report of Independent Auditors

To the Board of Commissioners of
Eugene Water & Electric Board

In our opinion, the financial statements of the Electric System Fund, the Water System Fund and the Trojan Project Fund of the Eugene Water and Electric Board (the "Board"), which are major funds that collectively comprise the Board's basic financial statements as listed in the index, present fairly, in all material respects, the respective financial position of each major fund of the Board, at December 31, 2004 and 2003, and the respective changes in financial position and cash flows thereof for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Board's management. Our responsibility is to express opinions on these financial statements based on our audits. We conducted our audits of these financial 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 opinions.

As discussed in Note 2, the December 31, 2004 and 2003 basic financial statements have been restated.

As discussed in Note 3, the Board changed the manner in which it accounts for realized gains and losses on physically settled derivative contracts not held for trading purposes, as of January 1, 2004.

The management's discussion and analysis for the year ended December 31, 2004 and 2003 on pages 3 through 12 is not a required part of the basic financial statements as of and for the year then ended but is supplementary information required by the accounting principles generally accepted in the United States of America. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

Our audit was conducted for the purpose of forming opinions on the financial statements that collectively comprise the Board's basic financial statements. The financial information included as supplementary information listed in the index is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information 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 resects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
February 2, 2005, except for Notes 2 and 13, as to which date is March 25, 2005

I, Ann E. Rhoads, do affirm that I am an independent certified public accountant holding unrevoked certificate number 5251 in the State of Oregon.

I have signed the above opinion as a partner of the firm of:

PricewaterhouseCoopers LLP
1300 SW Fifth Avenue, Suite 3100
Portland, Oregon 97201

Ann Rhoads

Ann E. Rhoads

Management’s Discussion and Analysis

The Eugene Water & Electric Board ("Board") is an administrative unit of the City of Eugene, Oregon and is responsible for the operation of the water and electric utilities of the City. The responsibilities delegated to the Board pursuant to the City Charter are conducted under the direction of a publicly elected board of five commissioners. The Board operates vertically integrated electric and water utilities that serve 83,000 electric customers and 48,300 water customers. The Board is also a 30.0% owner of the Trojan Nuclear Project.

In prior years, the Board's basic financial statements did not include transactions related to the Trojan Project Fund (discussed in Notes 2 and 13 to the financial statements). In 2004 the Board determined that the Trojan Project Fund should be included. The impact of the restatement is inclusion of an additional enterprise fund column in the basic financial statements and inclusion of additional note disclosures, primarily in Note 13. In addition, management discussion and analysis for the Trojan Project Fund are included in this report.

Financial Policies and Controls
The Board's financial management system consists of financial policies, financial management strategies, and the internal control structure, including the annual budgets and external audit of its financial statements. The Board has the exclusive right to determine rates and charges for services provided. The Board has established standards for financial performance and rate competitiveness that place its financial performance above the average of publicly owned electric and water utilities. This objective is reflected in evaluations of creditworthiness performed by the major credit rating agencies. Current underlying ratings are:

	Fitch	Moody's	Standard & Poors
Electric System	A+	A1	AA-
Water System	AA	Aa3	AA

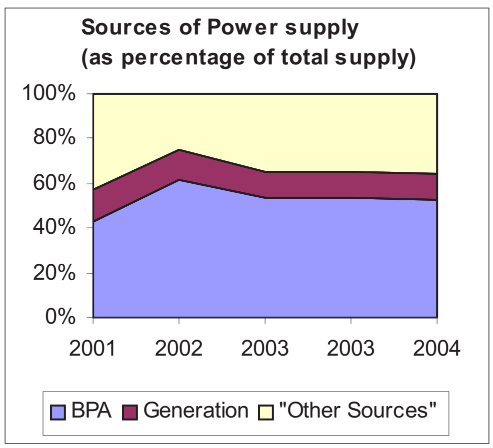
Power Supply Risk Management Policies
The Board must comply with State statues and City Charter that authorize and control its activities and the scope of its purchases and investments. Accordingly, the Board's activities in the power markets must be associated with the provision of electricity to meet anticipated sales and generation forecasts. To ensure this requirement is met, Board policies restrict the maximum long and short positions that can be taken relative to forward forecasts. The Board may grant exception to this policy to deal with specific circumstances, such as long-term resource acquisitions.

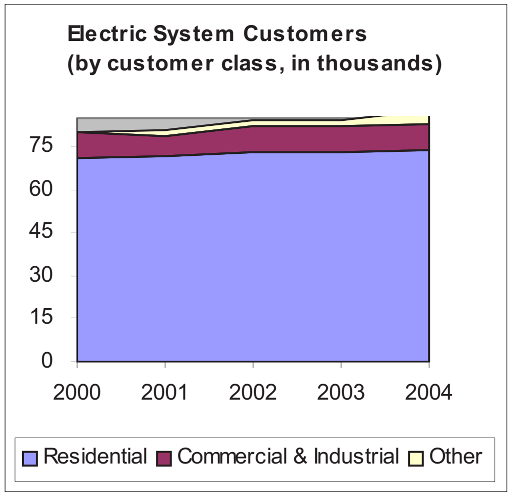
In addition to these anti-speculation provisions, the policies set standards for power supply counter-party creditworthiness. Credit exposure to all existing and potential counter-parties is reviewed on a continuous basis and actions are taken to either obtain security or restrict business transactions so as to be consistent with the credit evaluation.

Electric System
The Electric System serves a 238-square mile area, including the City and adjacent suburban areas. Power supply requirements are met primarily from hydroelectric sources, including self-generation and purchases from Bonneville Power Administration ("BPA"). Heating load and general economic conditions are the primary influences on retail sales. However, overall financial condition is influenced to a much greater degree by the availability of water for generation that is in excess of historically critical conditions both locally and regionally.

The Electric System in 2004 and 2003 purchased 53% and 54%, respectively, of its power used to serve retail load from BPA, the majority of which is provided under a "Slice of System" contract with the remainder obtained under a standard output ("Block") contract. Under the Slice agreement the Board has rights to 2.4% of the output of the federal BPA system. At critical water conditions this portion of output, together with the Board's self-generation is sufficient to serve retail load. The price of Slice power is set assuming critical water conditions. To the extent water conditions are above critical, the resulting secondary output is obtained at no additional charge.

However, during 2004 and in prior years, the Board's budgeting and revenue forecasting processes assumed normal water conditions and an average price for wholesale sales of the secondary power that is surplus to its retail needs. Sales prices are supported by output sales into forward markets and by financial instruments that have the effect of setting a minimum price for sales of secondary power. Unfortunately streamflows in the region have been less than normal for the last five years and have ranged from 54% to 97% based on a 30 year average. During 2004 the Board changed its budgeting and forecasting process to assume that available water for generation is 85% of the normal precipitation. The result of this change was an increase in electric rates in October 2004.




Electric System Customers
(by customer class, in thousands)
75
60
45
30
15
0
2000
2001
2002
2003
2004
Residential
Commercial & Industrial
Other

Financial Summary and Analysis
During 2004 the Electric System's gross operating revenues increased by $3 million (or 1%). Retail revenues increased by $11 million (7%) as a result of two retail rate increases (5% in April and 6% in October). Wholesale sales decreased by $8 million (15%) as a result of increased bookout activity (transactions with sale and purchase components that are not physically delivered), which are presented as net sales or net purchases under an accounting standard implemented in 2004. (Bookouts in 2003 were reclassified to conform to the 2004 presentation.) Prior to the netting of bookouts, wholesale sales had increased by $9 million in comparison to the prior year. However, results of overall net operating revenue increased $12 million over 2003 on a consistent measurement basis.

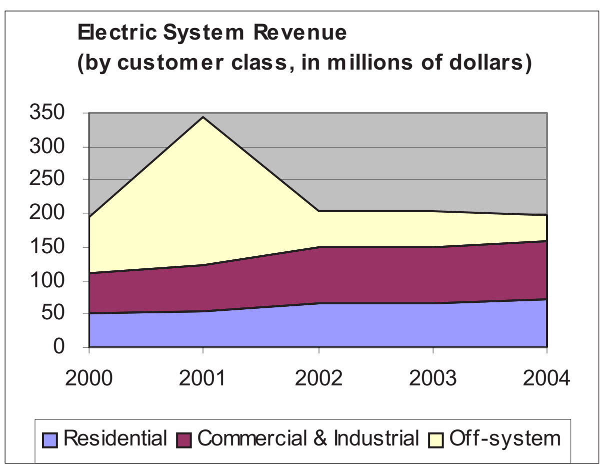
During 2003 the Electric System's gross operating revenues increased by $26.6 million (or 13%). Retail revenues remained essentially unchanged. The largest factor in the increase in operating revenue was the large increase in wholesale sales, which was up by 47% ($26 million). This performance was the result of:

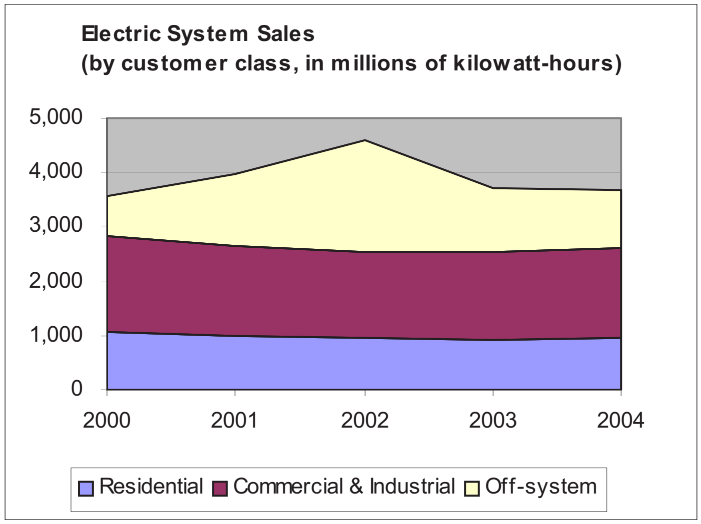
- Wholesale pries that averaged $10 per mWh higher than in 2002
- 470,000 mWh of additional output available for wholesale sales.

Resulting net operating revenue increased by $1.7 million (by 6.4%).

Electric rates increased during 2004 to fund deferred capital improvements, changes in Bonneville wholesale rates, and a reduction in the assumed amount of power available for resale as a result of lower assumed precipitation.

Included in the rates in 2003 was a surcharge designed to recover from the effects of the energy crisis of 2000-01. This event necessitated the borrowing of $30 million in 2001-02 to support working capital requirements for the purchase of wholesale power at unusually high prices. This borrowing was fully retired during 2003. The surcharge was discontinued in October of 2004.





Selected Financial Data

(in millions of dollars)	2004	2003	2002
Operating revenue	$ 211	$ 209	$ 209
Operating expenses	171	181	183
Net operating income	$ 40	$ 28	$ 26
Income before contributed capital	$ 19	$ 9	$ 9
Contributed capital	3	2	2
Change in net assets	$ 22	$ 11	$ 11
Total assets	$ 396	$ 378	$ 377
Total liabilities	254	258	268
Total net assets	$ 142	$ 120	$ 109

Capital Asset and Long-Term Debt Activity
Total utility plant in service as of December 31, 2004, 2003 and 2002 consisted of the following:

(in millions of dollars)	2004	2003	2002
Generation	$ 171	$ 160	$ 136
Transmission and distribution	218	205	197
General plant	67	65	66
Total plant in service	$ 456	$ 430	$ 399

As of December 31, 2004, the Electric System had $454 million, an increase from $430 million in 2003 and $399 million in 2002, of plant-in-service. Additions to electric plant consisted primarily of relicensing related improvements to the Leaburg Hydroelectric Project and the distribution system. Utility plant net of depreciation was $211 million and $195 million at December 31, 2004 and 2003, respectively. This represented an increase in net plant of $16 million (or 8%) over 2003. Capital construction was provided for through a combination of construction fees, cash flow from revenues, and long-term revenue bonds.

Total liabilities as of December 31 2004, 2003 and 2002 consisted of the following:

(in millions of dollars)	2004	2003	2002
Total current liabilities	$ 42	$ 42	$ 58
Total noncurrent liabilities	212	216	210
Total liabilities	$ 254	$ 258	$ 268

The Board issues revenue bonds to provide for the construction of capital facilities. At year end, the Electric System had $209 million of revenue bonds outstanding versus $214 million in 2003 and $212 million in 2002. No additional bonds were issued during 2004. During 2003 the Electric System Revenue and Refunding Bonds were issued in the amount of $40.9 million to refund the Series 1994 and Series 1998B bonds at lower rates of interest and to finance $5.8 million of hydroelectric project relicensing costs.

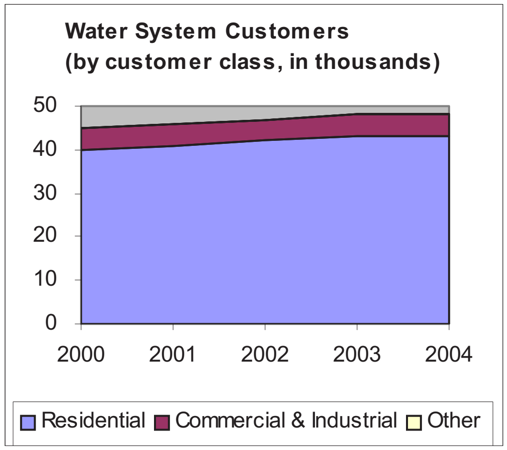
Economic Factors, Rates, and Outlook
During 2005 retail electric rates are expected to change so as to pass through the effects of Bonneville wholesale rate changes. The Board is also expected to issue revenue bonds during 2005 to provide for the additions to electric plant for relicensing related improvements to the Carmen Smith Hydroelectric Project and costs associated with investigating the relocation of the Board's Headquarters and operations facilities.

The Federal Energy Regulatory Commission license to operate the Carmen Smith Hydroelectric Project expires in 2008. Continued operation of the project requires the submission of an extensive license application requiring substantial scientific study and consultation with environmental and regulatory agencies. The application is due to be submitted in 2006.

The Board expects to issue up to $10 million in Electric Revenue Bonds during 2005 to complete the application process. The level of capital improvements to be required by the new license cannot be determined at this time.

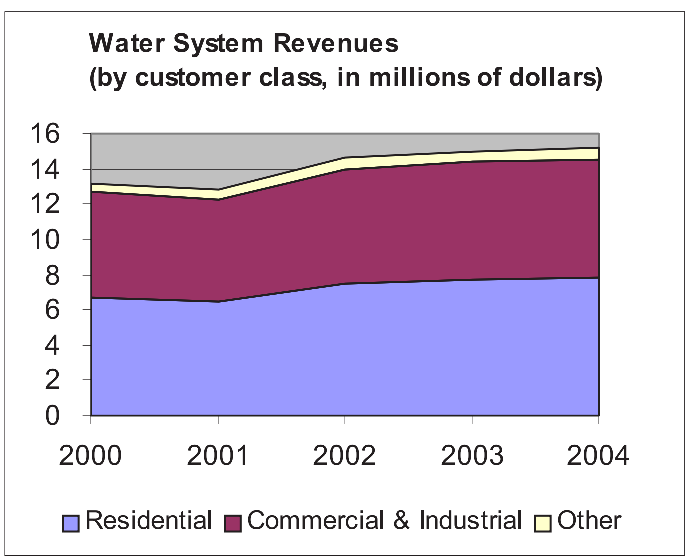
Water System

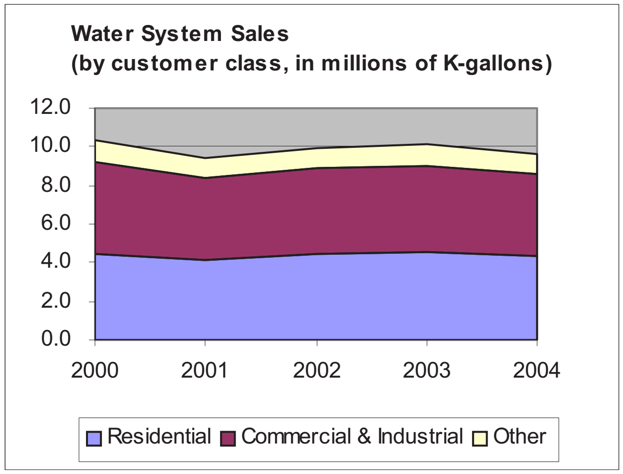
The Water System provides water to all areas within Eugene, and two water districts and one private water utility outside Eugene. During 2004 the Water System sold 1.0 billion gallons of water (10% of total sales) to the water districts. In 2003 the Water System sold 1.102 billion gallons of water (11% of total sales) to the water districts. Water is supplied from the McKenzie River and is treated at the Hayden Bridge Filtration Plant, the largest full-treatment plant in Oregon. Water is pumped from the Hayden Bridge Filtration Plant into the distribution system through two large transmission mains. The water distribution system consists of 25 enclosed reservoirs with a combined storage capacity of 92 million gallons, 31 pump stations and over 700 miles of distribution mains.



Financial Summary and Analysis
During 2004 Water System operating revenues increased by $248,000 (or 2%). However, due to generally higher operation and maintenance costs net operating revenues decreased by $608,000 (or 28%), resulting in net income of $2 million, which is 42% less than in 2003. However, water rates were increased in April of 2004 by 6% to pay for the higher operational costs.

During 2003, Water System operating revenues increased by $281,000 (or 2%). However due to generally higher operation and maintenance costs net operating revenues decreased by $357,000 (or 14%), resulting in net income of $3.1 million which is 6.5% less than 2002.





Selected Financial Data

(in millions of dollars)	2004	2003	2002
Operating revenue	$ 15	$ 15	$ 15
Operating expenses	13	13	12
Net operating income	$ 2	$ 2	$ 3
Income before contributions	$ 2	$ 3	$ 3
Contributed capital	1	2	1
Change in net assets	$ 3	$ 5	$ 4
Total assets	$ 86	$ 86	$ 79
Total liabilities	41	43	41
Total net assets	$ 46	$ 43	$ 38

Capital Asset and Long-Term Debt Activity
Total Water System plant in service as of December 31, 2004, 2003 and 2002 consisted of the following:

(in millions of dollars)	2004	2003	2002
Production	$ 30	$ 30	$ 16
Transmission and distribution	66	63	58
General plant	5	4	4
Total water system plant in service	$ 101	$ 97	$ 78

As of December 31, 2004, the Water System had $101 million invested in a variety of capital assets, an increase from $97 million in 2003 and $78 million in 2002. Utility plant net of accumulated depreciation was $40 million, an increase from $38.3 million in 2003. This represented an increase in plant of $1 million, net of depreciation (or 4%) over 2003, which is attributable to the completion of construction of a new 20 million gallon reservoir at the Hayden Bridge Filtration Plant. Capital construction is provided for through a combination of construction fees, cash flow from revenues, and long-term revenue bonds.

Total liabilities as of December 31, 2004, 2003 and 2002 consisted of the following:

(in millions of dollars)	**2004**	**2003**	**2002**
Total current liabilities	$ 3	$ 4	$ 3
Total noncurrent liabilities	38	39	38
Total liabilities	$ 41	$ 43	$ 41

At December 31, 2004 the Water System had $33 million of revenue bonds outstanding versus $34 million at December 31, 2003 and 2002. No Water System Revenue Bonds were issued during 2004 or 2003.

System Rates
During 2005 water rates are expected to remain unchanged. However, the administrative and support facilities for the Water System are shared with the Electric System facilities, and as mentioned above, the Board is investigating relocating these facilities during the next year.

Trojan Project (as restated)

The Trojan Nuclear Plant ("Trojan" or "Trojan Project") is jointly owned by Portland General Electric Company ("PGE"), 67.5%; Eugene Water & Electric Board (the "Board"), 30%; and Pacific Power & Light Company, 2.5%. The Project's financial statements reflect the Board's 30% ownership of Trojan.

In January of 1993, PGE ceased commercial operation of Trojan. PGE made the decision, which was later approved by each project partner, to shutdown Trojan. Accordingly, in 1993 the Project wrote off the nuclear reactor portion of the plant in service, along with other assets no longer in use. During 1995 the remaining plant was written off. The Project has also recorded a provision for decommissioning costs based on an estimate in current dollars and a receivable from Bonneville Power Administration ("BPA") representing BPA's responsibility to pay for all Trojan costs.

Prior to ceasing operations, the Board had previously assigned to BPA and other public agency participants its 30% share of the output from Trojan. Accordingly, BPA is obligated to pay the Board's share of all Trojan Project costs, including decommissioning and debt service in the form of net billing agreements. The Trojan Project fund has zero net assets as all amounts represent pass through of costs to BPA. By the terms of Trojan's outstanding bonds, there is no pledge of revenues from the Electric or Water Systems of EWEB to pay Trojan debt.

Financial Summary and Analysis
During 2004 the Project experienced a reduction in assets and liabilities of $12.5 million. In conjunction with minor offsetting items, the key factors influencing these results include:

- Reduction in BPA receivable by $13.6 million
- Decrease in the provision for decommissioning costs of $5.2 million and reduction in long-term debt of $7.4 million

During 2003 the Board experienced a reduction in assets of $45.1 million. The factors influencing these results include:

- Transfer of $5.7 million from the decommissioning reserve fund to the general fund to pay decommissioning costs
- Lower provision for decommissioning costs by $37.6 million than the previous year, $14.9 million due to continued plant decommissioning efforts and $22.7 million (net) due to the adoption of SFAS No. 143. This decreased the amount due from BPA in current dollars.

Selected Financial Data (as restated)

(in thousands of dollars)	**2004**	**2003**	**2002**
Net billings credits	$ 7,406	$ 5,419	$ 5,461
Decommissioning and other related costs	1,533	(209)	1,968
Long-term receivable, BPA *	61,939	75,608	111,607
Provision for decommissioning *	41,245	46,477	84,055
Long term debt	34,615	42,085	-
Total assets *	85,813	98,273	143,313
Total liabilities *	85,813	98,273	143,313

* As described in Note 13 to the financial statements, the decommissioning liability as of January 1, 2003 was adjusted due to the adoption of SFAS No. 143, which reduced the decommissioning liability by $24.4 million.

The Provision for decommissioning costs is a liability representing the future estimate for the remaining costs for equipment removal, embedded pipe remediation, surface contamination, nonradiological decontamination and on-site spent nuclear fuel storage (until permanent storage is provided by the U.S. Department of Energy). During 2004 the fund paid $8.7 million on behalf of BPA to PGE for decommissioning costs. In 2003 the fund paid $12.7 million respectively.

Long-Term Debt Activity

Total Liabilities as of December 31, 2004, 2003 and 2002 consisted of the following:

(in thousands of dollars)	**2004**	**2003**	**2002**
Total current liabilities	$ 9,952	$ 9,711	$ 10,154
Total long-term debt	34,616	42,085	49,104

At year end the Project had $45 million in long-term bonded debt outstanding as compared to $52 million last year. In 2005 the Board expects to refinance the bonds to take advantage of the lower interest rates currently available.

Economic Factors and Outlook

Transfer of the spent nuclear fuel to a temporary storage facility was completed ahead of schedule in 2003 and license termination is anticipated in 2005. The license termination is based on an estimate of the remaining decommissioning activities being completed by 2005. However, costs to operate and maintain the interim dry storage facility which houses the spent nuclear fuel will continue until permanent storage is available.

Basic Financial Statements

Eugene Water & Electric Board
Electric, Water Systems and Trojan Project
Balance Sheets
As Restated
December 31, 2004 and 2003

	Electric System		Water System	
	2004	2003	2004	2003
Assets				
Plant in service	$ 453,744,241	$ 429,872,438	$ 100,825,661	$ 96,978,806
Less accumulated depreciation	242,395,323	234,390,397	61,174,252	58,663,269
	211,348,918	195,482,041	39,651,409	38,315,537
Property held for future use	739,429	739,429	903,106	1,012,606
Construction work in progress	29,677,675	35,233,928	12,802,778	12,103,261
Net utility plant	241,766,022	231,455,398	53,357,293	51,431,404
Bond funds	-	-	-	-
Reserve and contingency fund	-	-	-	-
Construction funds	2,113,180	10,120,491	8,698,806	8,677,696
Investments for debt service	6,913,732	7,551,594	1,073,994	1,090,540
Restricted cash and investments	9,026,912	17,672,085	9,772,800	9,768,236
Cash and cash equivalents	6,303,576	16,175,280	871,047	2,394,924
Short-term investments	8,902,193	3,016,905	-	-
Designated investments				
Purchased power reserve	3,130,346	-	-	-
Capital improvement fund	4,341,692	-	10,438,258	10,688,075
Operating fund	784,211	823,716	1,254,658	1,333,056
Pension and medical reserve	5,582,975	1,469,596	1,190,097	366,400
Receivables, less allowances	35,924,375	31,823,985	1,444,913	1,188,494
Materials and supplies, at average cost	2,173,215	2,070,264	426,956	479,106
Prepayments and special deposits	4,694,454	5,751,534	523,262	495,227
Current assets	71,837,037	61,131,280	16,149,191	16,945,282
Prepaid retirement obligation	19,959,985	20,881,214	4,989,993	5,220,301
Investment in Western Generation Agency	9,674,585	9,819,504	-	-
Long-term receivable, conservation and other	5,310,347	5,644,107	-	-
Note receivable, water	5,220,302	5,450,610	-	-
Long-term receivable, BPA, net				
Deferred charges and other	33,045,443	26,302,029	2,119,593	2,374,638
Other assets	73,210,662	68,097,464	7,109,586	7,594,939
Total assets	$ 395,840,633	$ 378,356,227	$ 86,388,870	$ 85,739,861
Liabilities				
Accounts payable	$ 29,062,284	$ 29,913,446	$ 600,917	$ 2,376,796
Accrued payroll and benefits	2,838,121	2,458,657	554,987	486,250
Accrued interest on long-term debt	4,370,591	4,695,109	712,534	727,830
Long-term debt due within one year	6,145,000	4,645,000	860,000	825,000
Current liabilities	42,415,996	41,712,212	2,728,438	4,415,876
Long-term debt, bonds payable	203,371,308	209,494,599	32,089,452	32,898,129
Note payable, electric	-	-	5,220,302	5,450,610
Other liabilities and deferred credits	8,168,223	7,054,238	599,546	401,213
Accumulated provision for decommissioning costs	-	-	-	-
Total liabilities	253,955,527	258,261,049	40,637,738	43,165,828
Net Assets				
Invested in capital assets, net of related debt	73,001,388	66,439,004	28,092,558	25,465,593
Restricted for				
Capital projects	2,113,180	2,376,133	301,555	192,549
Debt service	6,913,732	7,551,594	1,073,994	1,090,540
Unrestricted	59,856,806	43,728,447	16,283,025	15,825,351
Total net assets	141,885,106	120,095,178	45,751,132	42,574,033
Total liabilities and net assets	$ 395,840,633	$ 378,356,227	$ 86,388,870	$ 85,739,861

Note: Inter system balances have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

Eugene Water & Electric Board
Electric, Water Systems and Trojan Project
Balance Sheets
As Restated
December 31, 2004 and 2003

	Trojan Project (Note 13)		Total Systems	
	2004	2003	2004	2003
Assets				
Plant in service	$ -	$ -	$ 554,569,902	$ 526,851,244
Less accumulated depreciation	-	-	303,569,575	293,053,666
	-	-	251,000,327	233,797,578
Property held for future use	-	-	1,642,535	1,752,035
Construction work in progress	-	-	42,480,453	47,337,189
Net utility plant	-	-	295,123,315	282,886,802
Bond funds	10,561,506	10,559,623	10,561,506	10,559,623
Reserve and contingency fund	2,001,065	2,002,213	2,001,065	2,002,213
Construction funds	-	-	10,811,986	18,798,187
Investments for debt service	3,531,533	3,525,622	11,519,259	12,167,756
Restricted cash and investments	16,094,104	16,087,458	34,893,816	43,527,779
Cash and cash equivalents	7,152,151	6,244,065	14,326,774	24,814,269
Short-term investments	-	-	8,902,193	3,016,905
Designated investments				
Purchased power reserve	-	-	3,130,346	-
Capital improvement fund	-	-	14,779,950	10,688,075
Operating fund	-	-	2,038,869	2,156,772
Pension and medical reserve	-	-	6,773,072	1,835,996
Receivables, less allowances	420,445	-	37,745,105	33,004,622
Materials and supplies, at average cost	-	-	2,600,171	2,549,370
Prepayments and special deposits	186,132	306,000	5,403,848	6,552,761
Current assets	7,758,728	6,550,065	95,700,328	84,618,770
Prepaid retirement obligation	-	-	24,949,978	26,101,515
Investment in Western Generation Agency	-	-	9,674,585	9,819,504
Long-term receivable, conservation and other	-	-	5,310,347	5,644,107
Note receivable, water	-	-	5,220,302	5,450,610
Long-term receivable, BPA, net	61,939,315	75,607,606	61,939,315	75,607,606
Deferred charges and other	20,650	28,170	33,994,994	27,315,697
Other assets	61,959,965	75,635,776	141,089,521	149,939,039
Total assets	$ 85,812,797	$ 98,273,299	$ 566,806,980	$ 560,972,390
Liabilities				
Accounts payable	$ 1,144,816	$ 1,201,616	$ 30,763,389	$ 33,484,001
Accrued payroll and benefits	-	-	3,393,108	2,944,907
Accrued interest on long-term debt	877,133	1,024,338	5,960,258	6,447,277
Long-term debt due within one year	7,930,000	7,485,000	14,935,000	12,955,000
Current liabilities	9,951,949	9,710,954	55,051,755	55,831,185
Long-term debt, bonds payable	34,615,689	42,085,345	270,076,449	284,478,073
Note payable, electric	-	-	5,220,302	5,450,610
Other liabilities and deferred credits	-	-	7,577,077	6,066,311
Accumulated provision for decommissioning costs	41,245,159	46,477,000	41,245,159	46,477,000
Total liabilities	85,812,797	98,273,299	379,170,742	398,303,179
Net Assets				
Invested in capital assets, net of related debt	-	-	101,093,946	91,904,597
Restricted for				
Capital projects	-	-	2,414,735	2,568,682
Debt service	-	-	7,987,726	8,642,134
Unrestricted	-	-	76,139,831	59,553,798
Total net assets	-	-	187,636,238	162,669,211
Total liabilities and net assets	$ 85,812,797	$ 98,273,299	$ 566,806,980	$ 560,972,390

Note: Inter system balances have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

Eugene Water & Electric Board
Electric, Water Systems and Trojan Project
Statements of Revenues, Expenses and Changes in Fund Net Assets
As Restated
Years Ended December 31, 2004 and 2003

	Electric System		Water System	
	2004	2003	2004	2003
Residential	$ 70,407,141	$ 65,572,237	$ 7,811,181	$ 7,744,121
Commercial and industrial	93,571,025	87,652,063	6,726,968	6,654,150
Sales for resale and other	47,100,177	56,344,640	689,018	581,192
Operating revenues	211,078,343	209,568,940	15,227,167	14,979,463
Purchased power	102,049,042	113,319,969	-	-
System control	4,049,527	3,775,859	-	-
Wheeling	9,983,934	13,011,389	-	-
Steam and hydraulic generation	9,983,462	9,674,398	-	-
Transmission and distribution	13,506,069	11,095,746	4,549,483	4,137,644
Source of supply, pumping and purification	-	-	2,691,008	2,419,349
Customer accounting	7,081,874	6,190,618	943,472	882,607
Conservation expenses	1,499,279	1,410,185	491,424	539,963
Administrative and general	12,220,875	12,838,658	2,515,566	2,620,362
Depreciation on utility plant	10,946,247	10,089,090	2,492,339	2,227,293
Operating expenses	171,320,309	181,405,912	13,683,292	12,827,218
Net operating income	39,758,034	28,163,028	1,543,875	2,152,245
Net billing credits	-	-	-	-
Interest and investment revenue	1,901,818	2,054,890	291,402	333,090
Allowance for funds used during construction	333,944	265,799	31,938	231,582
Other revenue	2,355,375	2,941,604	1,751,568	2,074,692
Other revenues	4,591,137	5,262,293	2,074,908	2,639,364
Decommissioning expenses	-	-	-	-
Contributions in lieu of taxes	10,466,872	9,866,496	-	-
Other revenue deductions	4,102,553	4,654,375	5,615	8,598
Accretion expense	-	-	-	-
Interest expense and related amortization	11,283,547	10,529,883	1,847,784	1,902,377
Allowance for borrowed funds used during construction	(478,659)	(463,662)	(26,046)	(208,598)
Other expenses	25,374,313	24,587,092	1,827,353	1,702,377
Income before contributed capital	18,974,858	8,838,229	1,791,430	3,089,232
Contributed capital	2,815,070	2,411,697	1,385,669	1,523,772
Change in net assets	21,789,928	11,249,926	3,177,099	4,613,004
Total net assets at beginning of year	120,095,178	108,845,252	42,574,033	37,961,029
Total net assets at end of year	$ 141,885,106	$ 120,095,178	$ 45,751,132	$ 42,574,033

Note: Inter system activities have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

Eugene Water & Electric Board
Electric and Water Systems
Statements of Revenues, Expenses and Changes in Fund Net Assets
Years Ended December 31, 2004 and 2003

	Trojan Project (Note 13)		Total Systems	
	2004	2003	2004	2003
Residential	$ -	$ -	$ 78,218,322	$ 73,316,358
Commercial and industrial	-	-	99,025,158	93,021,569
Sales for resale and other	-	-	47,789,195	56,925,832
Operating revenues	-	-	225,032,675	223,263,759
Purchased power	-	-	102,049,042	113,319,969
System control	-	-	4,049,527	3,775,859
Wheeling	-	-	9,983,934	13,011,389
Steam and hydraulic generation	-	-	9,855,351	9,554,947
Transmission and distribution	-	-	17,765,880	14,920,248
Source of supply, pumping and purification	-	-	2,142,367	1,843,337
Customer accounting	-	-	8,025,346	7,073,225
Conservation expenses	-	-	1,990,703	1,950,148
Administrative and general	-	-	14,231,585	14,984,536
Depreciation on utility plant	-	-	13,438,586	12,316,383
Operating expenses	-	-	183,532,321	192,750,041
Net operating income	-	-	41,500,354	30,513,718
Net billing credits	7,405,696	5,419,196	7,405,696	5,419,196
Interest and investment revenue	373,889	423,762	2,567,109	2,811,742
Allowance for funds used during construction	-	-	365,882	497,381
Other revenue	-	-	3,908,498	4,817,851
Other revenues	7,779,585	5,842,958	14,247,185	13,546,170
Decommissioning and related expenses	1,532,735	(208,798)	1,532,735	(208,798)
Contributions in lieu of taxes	4,357	3,471	10,471,229	9,869,967
Other revenue deductions	-	-	4,108,168	4,662,973
Accretion expense	2,848,819	2,222,222	2,848,819	2,222,222
Interest expense and related amortization	3,393,674	3,826,063	16,525,005	16,258,323
Allowance for borrowed funds used during construction	-	-	(504,705)	(672,260)
Other expenses	7,779,585	5,842,958	34,981,251	32,132,427
Income before contributed capital	-	-	20,766,288	11,927,461
Contributed capital	-	-	4,200,739	3,935,469
Change in net assets	-	-	24,967,027	15,862,930
Total net assets at beginning of year	-	-	162,669,211	146,806,281
Total net assets at end of year	$ -	$ -	$ 187,636,238	$ 162,669,211

Note: Inter system activities have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

Eugene Water & Electric Board
Electric, Water Systems and Trojan Project
Statements of Cash Flows
Years Ended December 31, 2004 and 2003

	Electric System		Water System	
	2004	2003	2004	2003
Cash flows from operating activities				
Receipts from customers	$ 207,657,977	$ 208,029,371	$ 15,177,169	$ 15,065,730
Grant proceeds	384,354	24,863	-	1,309
Other receipts	2,075,845	2,816,747	1,710,467	2,071,652
Power purchases	(100,488,936)	(119,402,248)	-	-
Payments to suppliers	(36,002,417)	(35,121,341)	(6,475,192)	(2,897,825)
Payments to employees	(23,673,731)	(22,968,977)	(5,944,468)	(5,734,586)
Contribution in lieu of taxes	(10,433,976)	(9,672,283)		-
Net cash provided by operating activities	39,519,116	23,706,132	4,467,976	8,506,280
Cash flows from investing activities				
(Increase) decrease in short-term investments	(5,885,288)	3,545,183	-	-
(Increase) decrease in restricted cash and investments	8,645,172	19,421,798	(4,562)	152,196
(Increase) decrease in designated investments	(11,545,912)	(1,427,695)	(495,482)	993,149
Interest earnings on investments	1,797,895	1,932,867	291,404	333,090
Distribution from equity investment in WGA	372,714	345,010	-	-
Net cash (used in) provided by investing activities	(6,615,419)	23,817,163	(208,640)	1,478,435
Cash flows from noncapital financing activities				
Note receipts from water	230,308	230,308	(230,308)	(230,308)
Commercial paper payments	-	(10,000,000)	-	-
Net cash provided by (used in) noncapital financing activities	230,308	(9,769,692)	(230,308)	(230,308)
Cash flows from capital and related financing activities				
Receipts from BPA under net billing agreement	-	-	-	-
Payments of nuclear decommissioning and related costs	-	-	-	-
Proceeds from bonds	-	43,710,731	-	-
Bond principal payments	(4,645,000)	(40,529,000)	(773,679)	(790,000)
Additions to utility plant	(21,507,623)	(28,139,865)	(4,366,784)	(7,787,062)
Interest payments - net of related amortizations	(11,293,026)	(11,878,017)	(1,798,111)	(1,781,154)
Conservation receipts from BPA	2,312,638	2,452,800	-	-
Additions to conservation assets and other	(10,687,768)	(6,679,761)	-	(8,598)
Contributed capital	2,815,070	2,411,697	1,385,669	1,523,772
Net cash (used in) provided by capital and related financing activities	(43,005,709)	(38,651,415)	(5,552,905)	(8,843,042)
Net increase (decrease) in cash and cash equivalents	(9,871,704)	(897,812)	(1,523,877)	911,365
Cash and cash equivalents at beginning of year	16,175,280	17,073,092	2,394,924	1,483,559
Cash and cash equivalents at end of year	$ 6,303,576	$ 16,175,280	$ 871,047	$ 2,394,924
Reconciliation of operating income to net cash provided by operating activities				
Net operating income	$ 39,758,034	$ 28,163,028	$ 1,543,875	$ 2,152,245
Adjustments to reconcile net operating income to net cash provided by operating activities				
Depreciation	10,683,520	10,036,535	2,510,983	2,245,977
Contributions in lieu of taxes	(10,433,976)	(9,672,283)	-	-
Other revenue	2,421,330	3,026,401	1,736,781	2,074,692
Equity (income) loss from WGA	(227,795)	36,792	-	-
(Increase) decrease in assets				
Receivables	(4,544,087)	(2,379,592)	(266,269)	84,536
Materials and supplies	(102,951)	(15,206)	52,151	(104,496)
Prepayments and special deposits	1,057,080	(2,241,234)	400,719	197,505
Conservation loans, net	777,458	334,651	9,850	(12,047)
Prepaid retirement obligation	921,229	921,229	-	230,308
Deferred charges	(2,053,617)	(2,050,291)	(8,376)	75,047
Increase (decrease) in liabilities				
Accounts payable, accrued payroll and benefits	357,366	(3,992,519)	(1,710,070)	1,504,736
Deferred credits and other	905,525	1,538,621	198,332	57,777
Net cash provided by operating activities	$ 39,519,116	$ 23,706,132	$ 4,467,976	$ 8,506,280

Note: Inter system activities have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

Eugene Water & Electric Board
Electric, Water Systems and Trojan Project
Statements of Cash Flows
Years Ended December 31, 2004 and 2003

	Trojan Project (Note 13)		Total Systems	
	2004	2003	2004	2003
Cash flows from operating activities				
Receipts from customers	$ -	$ -	$ 221,507,318	$ 221,736,262
Grant proceeds	-	-	384,354	26,172
Other receipts	-	-	3,587,867	4,689,954
Power purchases	-	-	(100,488,936)	(119,402,248)
Payments to suppliers	-	-	(41,006,329)	(36,536,077)
Payments to employees	-	-	(29,618,199)	(28,703,563)
Contribution in lieu of taxes	-	-	(10,433,976)	(9,672,283)
Net cash provided by operating activities	-	-	43,932,099	32,138,217
Cash flows from investing activities				
(Increase) decrease in short-term investments	-	-	(5,885,288)	3,545,183
(Increase) decrease in restricted cash and investments	2,000,330	5,977,308	10,640,940	25,551,302
(Increase) decrease in designated investments	(5,911)	5,622	(12,047,305)	(428,924)
Interest earnings on investments	373,889	423,762	2,463,188	2,689,719
Distribution from equity investment in WGA	-	-	372,714	345,010
Net cash (used in) provided by investing activities	2,368,308	6,406,692	(4,455,751)	31,702,290
Cash flows from noncapital financing activities				
Note receipts from water	-	-	-	-
Commercial paper payments	-	-	-	(10,000,000)
Net cash provided by (used in) noncapital financing activities	-	-	-	(10,000,000)
Cash flows from capital and related financing activities				
Receipts from BPA under net billing agreement	20,599,830	14,773,098	20,599,830	14,773,098
Payments of nuclear decommissioning and related costs	(9,500,972)	(13,601,223)	(9,445,979)	(13,527,028)
Proceeds from bonds	-	-	-	43,710,731
Bond principal payments	(7,485,000)	(7,065,000)	(12,903,679)	(48,384,000)
Additions to utility plant	-	-	(25,874,407)	(35,926,927)
Interest payments - net of related amortizations	(3,073,015)	(3,489,850)	(16,164,152)	(17,149,021)
Conservation receipts from BPA	-	-	2,312,638	2,452,800
Additions to conservation assets and other	-	-	(10,687,768)	(6,688,359)
Contributed capital	-	-	4,200,739	3,935,469
Net cash (used in) provided by capital and related financing activities	540,843	(9,382,975)	(47,962,778)	(56,803,237)
Net increase (decrease) in cash and cash equivalents	2,909,151	(2,976,283)	(8,486,430)	(2,962,730)
Cash and cash equivalents at beginning of year	6,244,065	9,220,348	24,814,269	27,776,999
Cash and cash equivalents at end of year	$ 9,153,216	$ 6,244,065	$ 16,327,839	$ 24,814,269
Reconciliation of operating income to net cash provided by operating activities				
Net operating income	$ -	$ -	$ 41,301,909	$ 30,315,273
Adjustments to reconcile net operating income to net cash provided by operating activities				
Depreciation	-	-	13,194,503	12,282,512
Contributions in lieu of taxes	-	-	(10,433,976)	(9,672,283)
Other revenue	-	-	4,158,111	5,101,093
Equity (income) loss from WGA	-	-	(227,795)	36,792
(Increase) decrease in assets				
Receivables	-	-	(4,810,356)	(2,295,056)
Materials and supplies	-	-	(50,800)	(119,702)
Prepayments and special deposits	-	-	1,457,799	(2,043,729)
Conservation loans, net	-	-	787,308	322,604
Prepaid retirement obligation	-	-	921,229	1,151,537
Deferred charges	-	-	(2,061,993)	(1,975,244)
Increase (decrease) in liabilities				
Accounts payable, accrued payroll and benefits	-	-	(1,352,704)	(2,487,783)
Deferred credits and other	-	-	1,103,857	1,596,398
Net cash provided by operating activities	$ -	$ -	$ 43,987,092	$ 32,212,412

Note: Inter system activities have been eliminated from the total systems columns.

The accompanying notes are an integral part of these basic financial statements.

1. Reporting Entity

The Eugene Water & Electric Board (the “Board”) is an administrative unit of the City of Eugene, Oregon. However, as established by the Governmental Accounting Standards Board’s (“GASB”) definition of a reporting entity, the Board is considered a primary government and is not a component unit of another entity, nor are there any component units of which the Board is financially accountable.

The Board provides energy and water service primarily to residential, commercial and industrial customers located in a 238 square mile area, including the City of Eugene and adjacent suburban areas. The Board has the authority to fix rates and charges. In order to secure power resources, the Board has taken ownership of various generation facilities. In addition, the Board has entered into joint ventures, whereby it has taken or anticipates taking an equity position in various generation facilities. The operations and sale of energy generated from the Board’s relationship with each of the facilities is subject to certain risks. Operations are contingent on various factors, such as regulation, flow levels, licensing agreements and weather patterns.

The Board owns 30.0% of the Trojan Nuclear Plant located along the Columbia River near Kelso, Washington. The project no longer operates and is being decommissioned pursuant to the Trojan Decommissioning Plan approved by the NRC in 1996. See further discussion in Note 13.

The Board is subject to various forms of regulation under federal, state and local laws and is subject to various Federal Energy Regulatory Commission regulations. Laws and regulations are subject to change and may have a direct impact on the operations of the Board.

The Bonneville Power Administration (“BPA”) acts as a power wholesaler, and the Board is committed to purchase minimum amounts of power from BPA under various forms of net billing agreements.

The Board is responsible for the ownership and operation of the Electric and Water Systems, and the basic financial statements include these two Systems and the Trojan Project.

2. Restatement

In prior years, the Board’s basic financial statements did not include transactions related to the Trojan Project Fund (discussed in Note 13). In 2004 the Board determined that the Trojan Project Fund should be included. The impact of the restatement is inclusion of an additional enterprise fund column in the basic financial statements and inclusion of additional note disclosures, primarily in Note 13.

Summary of the Trojan Project Fund Restatement

For 2004 and 2003 the nature of the error in previously issued financial statements and the effect of its correction had no impact to the Board's basic financial statements on changes in net assets or net assets at the end of the year. A summary of the total systems amount presented in the 2004 and 2003 financial statements, which are restated, is as follows:

	2004 as Previously Reported	2004 as Restated	2003 as Previously Reported	2003 as Restated
Balance sheets				
Assets				
Current assets	$ 87,986,228	$ 95,700,328	$ 78,076,562	$ 84,618,770
Total assets	477,009,201	566,806,980	458,645,478	560,972,390
Liabilities				
Current liabilities	45,144,434	55,051,755	46,128,088	55,831,185
Long-term debt, bonds payable	235,460,760	270,076,449	242,392,728	284,478,073
Accumulated provision for decommissioning costs	-	41,245,159	-	46,477,000
Total liabilities	289,372,963	379,170,742	295,976,267	398,303,179
Total liabilities and net assets	477,009,201	566,806,980	458,645,478	560,972,390
Statement of revenues, expenses and changes in fund net assets				
Other revenues	6,666,045	14,247,185	7,901,657	13,546,170
Other expenses	27,201,666	34,981,251	26,289,469	32,132,427
Statement of cash flows				
Net cash (used in) provided by investing activities	(6,824,059)	(4,455,751)	25,295,598	31,702,290
Net cash (used in) provided by capital and related financing activities	(48,558,614)	(47,962,778)	(47,494,457)	(56,803,237)
Net increase (decrease) in cash and cash equivalents	(11,395,581)	(8,486,430)	13,553	(2,962,730)

3. Summary of Significant Accounting Policies

Method of Accounting

The Board maintains its accounting records in accordance with generally accepted accounting principles for enterprise funds. The Board has applied all applicable GASB pronouncements, as well as Financial Accounting Standards Board ("FASB") pronouncements and Accounting Principles Board ("APB") opinions issued on or before November 30, 1989, unless those pronouncements conflict with or contradict GASB pronouncements. As allowed under GASB No. 20, the Board has elected to apply all FASB Statements and Interpretations issued after November 30, 1989, except for those that conflict with or contradict GASB pronouncements.

The Board accounts for its Electric and Water systems and the Trojan Project as proprietary funds.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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 prior year amounts have been reclassified to conform to current year presentation. Such reclassifications do not affect changes in net assets as previously reported.

Cash and Cash Equivalents
For purposes of the Statements of Cash Flows, the Board considers all highly liquid investments (other than restricted and designated assets) with original maturities of three months or less when purchased to be cash equivalents.

Operating Revenue
Operating revenue is recorded on the basis of service delivered. Utility revenues are derived primarily from the sale and transmission of electricity. Utility revenue from power sales and transmission is recognized when the power is delivered to and received by the customer. Estimated revenues are accrued for power deliveries not yet billed to customers from meter reading dates prior to month end (unbilled revenue) and are reversed the following month when actual billings occur. The credit practices of the Board require an evaluation of each new customer's credit worthiness on a case-by-case basis. At the discretion of management, a deposit may be obtained from the customer. Concentrations of credit risk with respect to receivables for residential customers are limited due to the large number of customers comprising the Board's customer base. Credit losses have been within management's expectations. Similar to its evaluation of residential, commercial and industrial customers credit reviews, the Board continually evaluates its wholesale power customers (sales for resale revenue) by reviewing credit ratings and financial credit worthiness of existing and new customers.

Revenues are recorded net of the allowance for doubtful accounts: $495,000 and $534,000 at December 31, 2004 and 2003 respectively for the Electric System, $31,000 and $42,000 at December 31, 2004 and 2003 respectively for the Water System. The allowance is determined by an examination of write off experience in the preceding five years, and consideration of other influences as appropriate. Total amounts written off at December 31, 2004 and 2003, respectively were $337,000 and $480,000 for the Electric System, $22,000 and 31,000 at December 31, 2004 and 2003, respectively for the Water System.

Approximately 18.1% of 2004 and 17.9% of 2003 Electric System's retail revenues, primarily residential, commercial and industrial, were the result of sales to two industrial customers. Approximately 3.9% of 2004 and 3.5% of 2003 Water System's operating revenues were the result of sales to one industrial customer.

Power Risk Management
The Board's Power Risk Management Guidelines set forth policies, limits and control systems governing power purchasing and sales activities for the Electric System. The objectives of such policies are to maximize benefits to customers from wholesale activities while minimizing the risk that wholesale activities will adversely affect retail prices. The Board does not enter into contracts for trading purposes.

In accordance with its policy guidelines, the Board utilizes derivative instruments to minimize its exposure to commodity price risk. These instruments include electricity forward, swap and option contracts and natural gas swap and option contracts. The contracts are considered derivative instruments under the provisions of FASB No. 133, *Accounting for Derivative Instruments and*

Hedging Activities, as amended, which requires that an entity recognize derivatives as assets or liabilities on its balance sheet and measure those instruments at fair value, unless they qualify for exceptions afforded by standard. Certain of the Board's forward purchase and sales contracts qualify under the normal purchases and sales exception under FASB No. 133 and FASB No. 149. Accordingly, the Board does not mark such contracts to market. The Board marks to fair value all other contracts which qualify as derivatives. These contracts extend through 2006, and have aggregate notional amounts totaling $4,405,000 ($18,776,300 at December 31, 2003). At December 31, 2004, net unrealized losses from derivative instruments required to be recorded at fair value by the standard aggregate $4,800,695 ($3,879,917 unrealized gains at December 31, 2003) for the Electric System. The Water System does not have any derivative contracts.

The Board reports unrealized gains and losses from its mark-to-market valuations as derivative assets or liabilities on its Balance Sheets. Such unrealized gains and losses are subject to regulatory deferral because they will be recoverable in rates when the forward contracts are executed in the future and, accordingly, are recognized as deferred charges or credits until realized upon execution of the related contracts.

In August 2003 the Financial Standards Accounting Board ratified Emerging Issues Task Force 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*. EITF 03-11 requires that revenues and expenses associated with nontrading 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 September 30, 2003, and does not require the reclassification of prior period amounts. While EITF 03-11 does not require the reclassification of prior periods, the Board has elected to reclassify the results of all prior periods presented. Effective with the adoption of EITF 03-11, the non-physical settlement of nontrading electricity derivative activities, formerly reported on a gross basis in both operating revenues and purchased power expense, are now recorded on a net basis. Net power purchases are included in purchase power expense and net power sales are included in sales for resale. This change, which has no effect on net operating income or cash flows, resulted in a $45,170,520 decrease in both operating revenues and purchased power expense for 2004 ($26,146,768 for 2003). Prospective application of EITF 03-11 will continue to result in a significant decrease in reported nontrading wholesale energy sales and purchases and related amounts reported in comparative financial statements.

Deferred Charges

The Board has deferred costs to be charged to future periods as allowed by FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*, which follows the premise that a utility should recognize expenses at the time when the ratemaking process authorizes them to be recovered with related revenues.

Conservation Assets

The Electric System defers substantially all of its costs associated with demand-side programs. Any reimbursements are credited (or netted) against the "conservation assets" and the net amount (asset) is amortized over five years. The net balance of conservation assets (costs less reimbursements, less amortization) at December 31, 2004 is $17,668,300 ($17,335,100 at December 31, 2003). Amortization expense of $3,876,900 in 2004 ($4,036,600 in 2003) is included in other revenue deductions.

With renewed analysis of the useful lives connected to the various kinds of conservation assets the Board invests in, the estimated life of 5 years for purposes of amortization was changed to 10 years in 2004. The variety of conservation programs and incentives the Board participates in has grown in recent years; periodic review of the benefit period is in the normal course of business.

Deferred Charges on Long-Term Debt

The Board has recorded deferred charges for certain bond issuance costs, which are being amortized over the life of the respective issue. The Electric System had an aggregate deferral of $2,835,800 at December 31, 2004 ($3,082,100 at December 31, 2003), and recorded $271,082 as amortization expense in 2004 ($252,000 in 2003). The Water System had an aggregate deferral of $521,700 at December 31, 2004 ($565,600 at December 31, 2003), and $43,900 was expensed in 2004 ($49,100 in 2003).

Sick Pay

The Board has recorded deferred charges for the future payment of sick leave expense of $1,264,300 at December 31, 2004 ($1,230,800 at December 31, 2003) for the Electric System and of $316,100 at December 31, 2004 ($307,700 at December 31, 2003) for the Water System.

Interest Rate Swap

In 2004, he Board entered into a fixed-to-floating LIBOR interest rate swap to help convert a portion its fixed long-term debt portfolio to floating rates. This reduces the Board's interest rate costs relative to the Series 1998A bonds and provides a variable rate debt component within its overall debt portfolio. In the swap transaction, the counterparty pays the Board a fixed 3.65 % interest rate on $10,945,000 declining notational amount for four years. The Board will pay the counter-party if the 30-day LIBOR interest rate is higher than 3.65%. The Board accounts for the interest rate swap at fair value and has deferred changes in fair value of $17,400 for the interest rate swap. This amount is recognized as a regulatory asset in deferred charges and as a liability to counterparty in deferred credits.

Preliminary Surveys

The Board has deferred certain costs associated with its investigation of several projects which it believes will be viable in the future, including deferred preliminary surveys of $5,359,400, primarily relating to the Carmen-Smith relicensing process, at December 31, 2004 ($753,900 at December 31, 2003).

Utility Plant and Depreciation

Utility plant is stated at original cost. Costs include labor, materials and related indirect costs, such as engineering, transportation and allowance for funds (i.e., interest) used during construction. The cost of additions, renewals and betterments is capitalized. Repairs and minor replacements are charged to operating expenses. The cost of property and removal cost, less salvage, is charged to accumulated depreciation when property is retired. Included in the Board's construction work-in-progress balance are costs associated with obtaining or renewing licensing agreements, as well as meeting other regulatory requirements. Once the new or renewed licensing agreements are obtained, the Board transfers those costs to its depreciable utility plant to be depreciated over the estimated useful lives of the plant components. Impairment losses as defined by FAS 144, whereby the carrying value of a long-lived asset group is not recoverable through the undiscounted cash flows expected from its use or disposal, are measured when the events or circumstances (typically changes in use of the asset or cash flow losses) make the value of the asset suspect. The Board did not have events or circumstances indicating the need to test for recoverability during 2004.

Depreciation is computed using straight-line group rates, which are equivalent to approximately 2.4% of the Electric System and 2.5% of the Water System original costs of depreciable utility plant.

Asset Retirement Obligations
Effective January 1, 2003, the Board adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires the recognition of an Asset Retirement Obligation ("ARO") for legal obligations associated with the retirement of tangible long-lived assets, including the recording of fair value of the liability, if reasonably estimable, for an ARO in the period in which it is incurred. The ARO liability is recorded as a capitalized cost increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. In the Board's judgment, it does not have any material legal obligations associated with the retirement of its tangible long-lived assets of the Electric and Water systems, except for certain assets with indefinite system lives for which the Board cannot estimate the ARO because the settlement date is indeterminable. The adoption of SFAS No. 143 did not have a material impact on the Board's financial condition or results of operations. See Note 13 for a discussion of ARO associated with the Trojan Project.

Debt Refundings
For current and advance refundings resulting in defeasance of debt, the difference between the reacquisition price and the net carrying amount of the old debt (gain or loss) is deferred and amortized as a component of interest expense over the remaining life of the old debt or the new debt, whichever is shorter, consistent with GASB Statement No. 23, and reported as a component of the new debt liability on the Balance Sheet.

Environmental Expenses
Environmental costs (i.e. fish and plant habitat enhancements) are expensed or capitalized depending upon their future economic benefits. Liabilities for such expenses are recorded when it is probable that obligations have been incurred and the costs can be reasonably estimated.

Net Assets
Net assets consist primarily of cumulative operating revenues collected by the Electric and Water Systems for (a) payment of utility plant additions or principal amortization of debt incurred for plant additions, in advance of net accumulated depreciation recognized on such plant, and (b) interest income earned on investments. It is the Board's intention to set rates at a level to continue replacing and improving net plant.

The Trojan Project Fund does not currently have net assets as all project costs and debt service are reimbursed by BPA (Note 13).

Fair Value of Financial Instruments
The carrying amounts of current assets, including restricted cash and investments, and current liabilities approximate fair value due to the short-term maturity of those instruments. The fair value of the Board's investments and debt are estimated based on the quoted market prices for the same or similar issues.

4. Cash and Investments

The Board maintains cash and investments in several fund accounts in accordance with bond resolutions and Board authorization. Descriptions of these fund account types are as follows:

See Note 13 for discussion of Trojan Project cash and investments.

Restricted Cash and Investments
Construction Funds
Used to account for legally restricted cash and investments for the purpose of construction of capital projects.

Investments for Debt Service
Used to account for cash and investments, which the Board has designated for future payment of principal and interest on debt.

Designated Investments
Purchased Power Reserve Fund
Used to account for cash and investments, which the Board has designated to reserve for fluctuations in purchased power costs.

Capital Improvement Fund
Used to account for cash and investments, which the Board has designated for capital improvements.

Operating Fund
Used to account for cash and investments, which the Board has designated for payment of operating costs and self-insured retention claims to maintain balances in the general account within target levels.

Pension and Medical Reserve Fund
Used to account for cash and investments that the Board has designated for pension and postretirement medical costs.

Deposits with financial institutions are comprised of bank demand deposits and savings accounts. The total bank balance, as recorded in the bank records at December 31, 2004, is $5,565,920 ($1,398,564 at December 31, 2003) for both the Electric and Water Systems. Of the bank balance, $100,000 was covered by federal depository insurance, and $5,465,920 was collateralized with securities held by the pledging financial institution but not in the Board's name. At December 31, 2004, the Board held $35,000,000 in collateral certificates.

The Board's investments during the year for all funds, which included obligations of the U.S. Government, are authorized by State Statutes and bond resolutions. The Board's investments are categorized to give an indication of the level of risk assumed by the Board at year end. Category 1 includes investments that are insured or registered, or for which securities are held by the Board or its agent in the Board's name. Category 2 includes uninsured and unregistered investments for which securities are held by the counterparty's trust department or agent in the Board's name. Category 3 includes uninsured and unregistered investments for which securities are held by the counterparty or by its trust department or agent, but not in the Board's name. The Board's investments are held in safekeeping in book entry form by the financial institution counterparty and are considered to be

Category 3 investments under the above criteria. The Board's investment in the State of Oregon Local Government Investment Pool ("LGIP") is not required to be categorized by level or risk because this investment is not evidenced by securities.

Investments, except for the investment in LGIP, are carried at fair value as allowed by GASB Statement No. 31, *Accounting and Financial Reporting for Certain Investments and for External Investment Pools*, using quoted market prices in 2004 and 2003. Also, as allowed by GASB Statement No. 31, the investment in LGIP is carried at amortized cost, which approximates fair value at December 31, 2004 and 2003.

The Board places its investments with financial institutions and limits the amount of credit exposure with any one financial institution. The Board actively evaluates the credit worthiness of the financial institutions with which it invests.

Cash and investments consist of the following at December 31, 2004:

	Restricted Cash and Investments	Cash and Cash Equivalents	Short-Term Investments	Designated Funds	Total Carrying Amount
Electric System					
Cash on hand	$ -	$ 11,800	$ -	$ -	$ 11,800
Cash in bank	-	4,679,683	-	-	4,679,683
Investment - Bank Certificate of Deposit	-	-	2,033,788	-	2,033,788
Investments - direct obligations of U.S. government	6,913,732	-	6,868,405	2,008,321	15,790,458
Investments in the State of Oregon Local Government Investment Pool	2,113,180	1,612,093	-	11,830,903	15,556,176
Total electric system	9,026,912	6,303,576	8,902,193	13,839,224	38,071,905
Water System					
Cash in bank	-	278,641	-	-	278,641
Investments - direct obligations of U.S. government	9,034,030	-	-	6,496,585	15,530,615
Investment in the State of Oregon Local Government Investment Pool	738,770	592,406	-	6,386,428	7,717,604
Total water system	9,772,800	871,047	-	12,883,013	23,526,860
	$ 18,799,712	$ 7,174,623	$ 8,902,193	$ 26,722,237	$ 61,598,765

Cash and investments consist of the following at December 31, 2003:

	Restricted Cash and Investments	Cash and Cash Equivalents	Short-Term Investments	Designated Funds	Total Carrying Amount
Electric System					
Cash on hand	$ -	$ 11,800	$ -	$ -	$ 11,800
Investments - direct obligations of U.S. government	9,589,588	-	3,016,905	-	12,606,493
Investments in the State of Oregon Local Government Investment Pool	8,082,497	16,163,480	-	2,293,312	26,539,289
Total electric system	17,672,085	16,175,280	3,016,905	2,293,312	39,157,582
Water System					
Investments - direct obligations of U.S. government	8,577,306	-	-	7,729,448	16,306,754
Investment in the State of Oregon Local Government Investment Pool	1,190,930	2,394,924	-	4,658,083	8,243,937
Total water system	9,768,236	2,394,924	-	12,387,531	24,550,691
	$ 27,440,321	$ 18,570,204	$ 3,016,905	$ 14,680,843	$ 63,708,273

5. Electric Utility Plant

The major classifications and depreciable lives of plant in service at December 31 are as follows:

	Depreciable Life-Years	Balance at December 31, 2003	Increases	Decreases	Balance at December 31, 2004
Land	-	$ 6,028,345	$ 105,046	$ -	$ 6,133,391
Steam production	10-25	21,559,505	-	(2,943,677)	18,615,828
Hydro production	36-50	119,360,717	10,939,186	(137,387)	130,162,516
Wind production	25	13,087,182	-	-	13,087,182
Transmission	33-50	51,691,375	1,986,401	-	53,677,776
Distribution	28.5	153,044,935	11,301,279	-	164,346,214
General plant	3-50	65,100,379	2,833,648	(212,693)	67,721,334
Total plant in service		429,872,438	27,165,560	(3,293,757)	453,744,241
Accumulated depreciation		(234,390,397)	(11,319,289)	3,314,363	(242,395,323)
Property held for future use		739,429	-	-	739,429
Construction work in progress		35,233,928	22,679,098	(28,235,351)	29,677,675
Net utility plant		$ 231,455,398	$ 38,525,369	$ (28,214,745)	$ 241,766,022

6. Water Utility Plant

	Depreciable Life-Years	Balance at December 31, 2003	Increases	Decreases	Balance at December 31, 2004
Land	-	$ 527,911	$ 109,500	$ -	$ 637,411
Structure	50	22,002,472	381,031	-	22,383,503
Pumping	20	5,901,645	257,622	-	6,159,267
Purification	25	1,128,635	28,567	-	1,157,202
Transmission	28.5	17,196,188	-	-	17,196,188
Reservoirs	50	10,897,483	73,978	-	10,971,461
Distribution	28.5	27,838,795	2,007,259	-	29,846,054
Services, meters and hydrants	20-28.5	7,106,602	836,235	-	7,942,837
General plant	3-50	4,379,075	203,079	(50,416)	4,531,738
Total plant in service		96,978,806	3,897,271	(50,416)	100,825,661
Accumulated depreciation		(58,663,269)	(2,570,770)	59,787	(61,174,252)
Property held for future use		1,012,606	-	(109,500)	903,106
Construction work in progress		12,103,261	4,213,401	(3,513,884)	12,802,778
Net utility plant		$ 51,431,404	$ 5,539,902	$ (3,614,013)	$ 53,357,293

7. Investment in Western Generation Agency

The Board is a party to an Intergovernmental Agency Agreement, whereby the Board was obligated to make equity investments in the Western Generation Agency (the "Agency") as partial funding for the construction of the Wauna Cogeneration Project (the "Project"). As of December 31, 1996, the Board had made all required equity investments, totaling $15,100,000, to the Agency. The Project agreements allow the Board to be repaid its equity investment plus a cumulative preferred dividend at 7.875% should the operating revenues of the Project be sufficient to cover operating costs, debt service, plus other reserve requirements. During 2004 distributions totaling $372,714 were received, all of which was a preferred equity distribution. The repayment of the entire equity investment is contingent upon the successful operation of the Project and is not guaranteed. Should the Project fail to generate sufficient revenues, the repayment of the equity contribution may occur only in part or not at all. At December 31, 2004, the Board has recorded a receivable in the amount of $583,965 ($598,641 at December 31, 2003) for the preferred dividend, which is included in other revenue.

The balance of the investment in Western Generation Agency as of December 31, 2004 was $9,674,585 and has been decreased by the equity distributions described above and increased by the Board's 50% share of Agency's 2004 net income, or $227,795. The Board is committed, through a power purchase agreement, to purchase the output from the Project through the year 2021. The Board has agreed to suspend its agreement with the Agency in favor of a separate purchase power agreement between the Agency and the BPA through the year 2016. Financial information for the Project is included in the financial statements of the Agency and may be obtained from the Agency's trustee, Wells Fargo Bank.

8. Long-Term Receivable, Conservation and Other

The Board has various efforts associated with conservation and renewable energy for which it expects payment in periods beyond the coming year.

The Board loans money to its customers for purposes of installing energy efficiency improvements to the customers' properties. The balance of such Conservation Loans on the part of the Electric System were $4,307,900 net of the current $1,688,000 portion at December 31, 2004 and $4,415,000 net of the current $2,358,000 portion at December 31, 2003.

Under an agreement with Bonneville Power Association, the Electric System receives semi-annual payments with interest for cost-effective conservation resources acquired during the years 1994 through 1999. The last payment on the note is scheduled for October 2013. The balance of the note was $1,011,400 at December 31, 2004, $83,400 of which is receivable in the coming year. The balance at December 31, 2003 was $1,099,800 of which $83,400 was included with current Receivables.

The Electric System receives payment from the US Department of Energy under the Renewable Energy Production Incentive ("REPI") Program for energy produced at its Foote Creek Rim Wind Project located in Wyoming. At December 31, 2004 the System estimated its receivable to be $383,100, of which $308,700 is classified as current and $74,400 is expected in 2006. At December 31, 2003 the receivable was $474,800: $345,500 current and $129,000 for receipt in 2005.

See Note 13 for discussion of Trojan Project's long-term receivable from BPA.

9. Long-Term Debt

Long-term portion of bonds payable at December 31:

	2004	2003
Electric Utility System Revenue and Refunding Bonds		
1996 Series, 12-10-96 issue		
Serial Bonds, 4.80% - 5.375%, due 2005-2013	$ 8,925,000	$ 9,815,000
Term Bonds, 5.60%, due 2014-2016	4,425,000	4,425,000
1997 Series, 10-1-97 issue, 4.45% - 5.00%, due 2005-2011	7,565,000	8,630,000
1998 Series, 2-1-98 issue		
Serial Bonds, 4.25% - 4.85%, due 2005-2015	9,655,000	9,710,000
Term Bonds, 5.00% - 5.05%, due 2016-2022	23,875,000	23,875,000
1998 Series A, 11-15-98 issue		
Serial Bonds, 5.66% - 5.97%, due 2005-2009	1,465,000	1,780,000
Term Bonds, 6.22% - 6.85%, due 2010-2023	9,165,000	9,165,000
2001 Series A, 11-15-01 issue		
Term Bonds, 6.32%, due 2005-2022	25,840,000	25,930,000
Capital appreciation, 7.13% - 7.20%, due 2023-2027	4,067,556	4,067,556
2001 Series B, 11-15-01 issue		
Serial Bonds, 4.00% - 5.25%, due 2005-2022	19,485,000	20,245,000
Term bonds, 5.00%, due 2023-2031	19,140,000	19,140,000
2002 Series A, 5-7-02 issue		
5.20%, due 2005-2011	8,800,000	10,010,000
2002 Series B, 6-1-02 issue		
4.375% - 5.96%, due 2005-2012	8,945,000	9,990,000
2002 Series C, 6-1-02 issue		
2.8% - 5.0%, due 2005-2022	11,420,000	11,885,000
2003 Series, 6-10-03 issue		
2.0% - 5.0%, due 2005-2022	40,410,000	40,660,000
	203,182,556	209,327,556
Add unamortized premium	3,113,613	3,461,927
Less unamortized refunding costs	(2,027,242)	(2,298,657)
Less unamortized discount	(897,619)	(996,227)
Electric System Bonds payable	203,371,308	209,494,599
Water Utility System Revenue and Refunding Bonds		
1997 Series, 10-1-97 issue, 4.45% - 4.55%, due 2005-2006	905,000	1,765,000
2000 Series, 6-1-00 issue, 5.20% - 5.875%, due 2007-2030	21,405,000	21,405,000
2002 series, 8-1-02 issue, 2.75% - 4.7%, due 2007-2022	10,000,000	10,000,000
Note payable - Electric		
11-15-01 issue, 6.32% - 7.21%, due 2005-2027	5,220,302	5,450,610
	37,530,302	38,620,610
Less unamortized discount	(187,819)	(201,141)
Less unamortized refunding costs	(32,729)	(70,730)
Water System Bonds payable	37,309,754	38,348,739
Total long-term portion of debt	240,681,062	247,843,338
Less inter system payable	5,220,302	5,450,610
Total long-term debt per balance sheets	$ 235,460,760	$ 242,392,728

Current and long-term debt, excluding the inter system payable, at December 31 is as follows:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Electric System	$ 209,516,308	$ 225,339,334	$ 214,139,599	$ 251,872,058
Water System	32,949,452	36,026,552	33,723,129	47,098,185
Total bonds payable	$ 242,465,760	$ 261,365,886	$ 247,862,728	$ 298,970,243

Total principal requirements reflective of the foregoing bonds, during the years 2005 through 2009 and thereafter, are as follows:

	Electric System	Water System	Total Systems
2005	$ 6,145,000	$ 860,000	$ 7,005,000
2006	7,535,000	905,000	8,440,000
2007	8,710,000	910,000	9,620,000
2008	9,310,000	940,000	10,250,000
2009	9,940,000	985,000	10,925,000
Thereafter	167,687,556	28,570,000	196,257,556
	$ 209,327,556	$ 33,170,000	$ 242,497,556

The resolutions authorizing the issuance of revenue bonds contain various covenants, sinking fund requirements and obligations with which the Board must comply.

The Board entered, but had not drawn on a nonrevolving demand line of credit on December 23, 2003 with a combination of prime and the LIBOR interest rate for a maximum of $30 million. The Board's previous $60,000,000 line of credit expired October 31, 2003 with no balance outstanding.

In June 2003 the Board issued $40,865,000 in Electric Utility Revenue and Refunding Bonds with interest rates from 2.0% to 5.0%, to advance refund the 1994 Series Bonds and the 1998B Series Bonds and for capital improvements in the Electric System. The Board deposited $2,300,000 in escrow from the issuance of the 1998B bonds to reduce the amount of the 2003 refunding.

Although the refunding resulted in an accounting loss of $384,700 to be amortized over the life of the defeased bond issues, the Board reduced its aggregate debt service payments by $5,016,300 over 20 years and obtained an economic gain (difference between the present values of the old and new debt service payments) of $2,431,500.

As of December 31, 2003, the amount of defeased debt still outstanding but removed from the Board's long-term debt amounted to $31,500,000 for the Electric System Distribution Division. At August 1, 2004, this debt matured.

Long-term debt activity for the year is as follows:

	Outstanding January 1, 2004	Issued During Year	Redeemed During Year	Outstanding December 31, 2004
Electric Revenue Bonds, with interest rates from 3.90% to 6.70%, maturing through 2031 (original issue $190,230,000)	$ 76,890,000	$ -	$ (2,330,000)	$ 74,560,000
Electric Revenue Refunding Bonds, with interest rates from 2.0% to 5.25%, maturing through 2022 (original issue $127,190,000)	107,085,000	-	(2,315,000)	104,770,000
Electric Revenue Current Interest Bonds, with interest rate of 6.23%, maturing through 2027 (original issue $29,997,556)	29,997,556	-	-	29,997,556
Total Electric System	213,972,556	-	(4,645,000)	209,327,556
Water Revenue Refunding Bonds, with interest rates from 4.45% to 4.55%, maturing through 2006 (original issue $6,615,000)	2,590,000	-	(825,000)	1,765,000
Water Revenue Bonds, with interest rates from 2.75% to 5.87%, maturing through 2030 (original issue $31,405,000)	31,405,000	-	-	31,405,000
Total Water System	33,995,000	-	(825,000)	33,170,000
Total bonded debt	$ 247,967,556	$ -	$ (5,470,000)	$ 242,497,556

	Outstanding January 1, 2003	Issued During Year	Matured During Year	Outstanding December 31, 2003
Electric Revenue Bonds, with interest rates from 3.90% to 6.70%, maturing through 2031 (original issue $190,230,000)	$ 115,284,000	$ -	$ (38,394,000)	$ 76,890,000
Electric Revenue Refunding Bonds, with interest rates from 2.0% to 5.25%, maturing through 2022 (original issue $127,190,000)	68,355,000	40,865,000	(2,135,000)	107,085,000
Electric Revenue Current Interest Bonds, with interest rate of 6.23%, maturing through 2027 (original issue $29,997,556)	29,997,556	-	-	29,997,556
Total Electric System	213,636,556	40,865,000	(40,529,000)	213,972,556
Water Revenue Refunding Bonds, with interest rates from 4.45% to 4.55%, maturing through 2006 (original issue $6,615,000)	3,380,000	-	(790,000)	2,590,000
Water Revenue Bonds, with interest rates from 2.75% to 5.87%, maturing through 2030 (original issue $31,405,000)	31,405,000	-	-	31,405,000
Total Water System	34,785,000	-	(790,000)	33,995,000
Total bonded debt	$ 248,421,556	$ 40,865,000	$ (41,319,000)	$ 247,967,556

See Note 13 for discussion of long-term debt of Trojan Project.

10. Power Supply Resources

The Board maintains purchase power agreements with BPA and various other regional utilities. These agreements began expiring during 2001 and will continue through 2031 and may be renewed at the Board's option, prior to expiration. A significant portion of the power received from BPA is provided under the "Slice" contract. The Slice contract provides for certain periodic adjustments and true-ups based on actual BPA costs. All BPA assessed true-ups have been fully accrued for 2004; however, certain of these costs are subject to refund by BPA upon certain findings.

Expected costs for power supply contracts are as follows:

2005	$ 87,785,000
2006	90,666,000
2007	94,972,000
2008	94,854,000
2009	94,825,000
Thereafter	330,535,000

Amounts to be paid under the Board's power supply contracts are subject to significant variation based on changes in rates and volumes, therefore the above should be considered estimates.

During 2004 the Board purchased approximately 53% of its power requirements from BPA, approximately 36% from sources other than BPA, and generated approximately 11% (54%, 35% and 11%, respectively, in 2003).

11. Retirement Benefits

Plan Description

The Board's pension plan provides retirement and disability benefits, annual cost-of-living adjustments and death benefits to members or their beneficiaries. The Board is a participating employer in the Oregon Public Employees Retirement System ("OPERS") and Oregon Public Service Retirement Plan ("OPSRP"). The OPERS Board administers both plans, which are established under Oregon Revised Statutes and acts as a common investment and administrative agent for public employers in the State of Oregon.

OPSRP was created during the 2003 Oregon Legislative session and represents the pension plan for public employees hired on or after August 29, 2003, unless membership was previously established in OPERS, which is a closed plan. All Board employees are eligible to participate in OPSRP after six months of employment. Benefits are established under both plans by State Statute and employer contributions are made at an actuarially determined rate as adopted by the Public Employees Retirement Board ("Retirement Board"). The OPERS, a component unit of the State of Oregon, issues a comprehensive annual report that includes both pension plans, which may be obtained by writing to PERS.

Funding Policy

OPERS reissued employer rates in July 2003 for the 2001 actuarial valuation based on the changes to the pension plan during the 2003 Legislative session. The Board's new rate effective July 1, 2003 was 11.85% and the rate was reduced to 11.32% effective November 1, 2004 as the result of litigation against OPERS. The OPERS is not expected to change employer contribution rates until after the 2003 actuarial valuation, which is expected to be available in February 2005.

State statute requires covered employees to contribute 6% of their salary to the system, but allows the employer to pay any or all of the employees' contribution in addition to the required employer's contribution. The Board has elected to pay the employees' contributions.

In December 2001, the Board elected to make a lump-sum payment of approximately $29,600,000, which had the effect of lowering the employer contribution rate to 15.51%, beginning January 1, 2002. The lump sum payment is recorded as an other asset and is being amortized over the funding period of 27 years. The amortization was $1,152,000 for 2004 and 2003, respectively.

Annual Pension Cost

Because all OPERS participating employers are required by law to submit the contributions as adopted by the Retirement Board, and because employer contributions are calculated in conformance with the parameters of GASB No. 27, *Accounting for Pensions by State and Local Government Employers*, there is no net pension obligation to report, and annual required contributions are equal to annual pension cost. For the year ended December 31, 2004, the Board's annual pension expense of $5,067,900, consisted of the employer portion of $3,353,500 and the annual required contribution of approximately $1,714,400 (an average for 2004 of 12% of covered payroll and 6%, respectively).

The Board's pension liability and the annual required contribution rate were determined as part of the December 31, 2001 actuarial valuation using the entry age actuarial cost method. The unfunded actuarial accrued liability is amortized as a level percentage of projected annual payroll on an open basis over a 26-year period. The actuarial assumptions include a rate of return on investment of present and future assets of 8.0% per year, projected salary increases of 4.25% (excluding merit and longevity increases), and cost-of-living adjustments of 2.0% per year for postretirement benefits. Investment return and projected salary increases include an inflation component of 3.5%.

The following table presents three-year trend information for the Board's employee pension plan:

Fiscal Year Ending	Annual Pension Cost (APC)	Percentage of APC Contributed
12-31-02	6,275,661	100%
12-31-03	5,221,700	100%
12-31-04	5,067,900	100%

The following table presents a schedule of funding progress for the Board's employee pension plan:

Valuation Date	Value of Assets	Actuarial Liability	Unfunded Actuarial Liability (UAL)	Percent of Actuarial Liability Funded	Covered Payroll	UAL/ Payroll
12-31-97	$ 58,946,228	$ 117,633,500	$ 58,687,272	50%	$ 25,992,756	226%
12-31-99	172,684,683	227,670,647	54,985,964	76%	27,087,320	203%
12-31-01 *	197,488,997	200,216,724	2,772,727	99%	27,068,757	10%

* Revised, including 2003 legislative action.

The Supplemental Retirement Plan

Plan Description

The Supplemental Retirement Plan is a single-employer plan providing retirement, death and disability benefits to participants and their beneficiaries. It has been in effect since January 1, 1968 and was last amended and restated July 1988. The objective of the plan is to provide a benefit on retirement, which, together with the benefit from OPERS, will provide 1.67% of the highest 36-month average salary for each year of service. Independent actuaries determine employer contributions.

Funding Policy

There is no required contribution rate as a percentage of payroll, since the only participants currently in the plan are retirees and their beneficiaries. Funding of the plan is made from Board contributions, as needed to meet obligations to retirees, together with earnings on plan assets. Amounts are recouped in rates as contributions are made.

Annual Pension Cost

Employer contributions are calculated and made in conformity with the parameters of GASB No. 27. The Board's annual pension cost is based upon its latest actuarial report, dated January 1, 2004, with the next actuarial valuation for the year ended December 31, 2004 scheduled to be completed during 2005.

The Board's pension liability and the annual required contribution rate were determined as part of the January 1, 2004 actuarial valuation using the unit credit method. The unfunded actuarial accrued liability is amortized as a level percentage of projected annual payroll on an open basis over a 10-year period. The actuarial assumptions include a rate of return on investment of present and future assets of 7.0% per year, cost-of-living adjustments of 2.0% per year for postretirement benefits, discount rate of 6% and 1983 Group Annuity Mortality rate.

The Board's annual pension cost and the change in net pension obligation related to the Supplemental Retirement Plan for the years ended December 31 is as follows:

	2004	2003
Annual recommended contribution	$ 548,494	$ 498,139
Interest on net pension obligation	114,318	84,418
Adjustment to annual recommended contribution	(210,453)	(155,409)
Annual pension cost	452,359	427,148
Contributions made	605,050	-
(Decrease) increase in net pension obligation	(152,691)	427,148
Net pension obligation, January 1	1,633,119	1,205,971
Net pension obligation, December 31	$ 1,480,428	$ 1,633,119

The following tables present ten-year trend information for the Board's Supplemental Retirement Plan:

	Annual Pension Cost (APC)	Percentage of APC Contributed	Net Pension Obligation
December 31, 2003	$ 452,359	134%	$ 1,480,428
December 31, 2002	427,148	0%	1,633,119
December 31, 2001	402,482	0%	1,205,971

Schedule of funding progress for the Supplemental Retirement Plan:

Valuation as of January 1	Value of Assets	Actuarial Liability	Net Assets as a Percent of Actuarial Liability	Unfunded Actuarial Liability
2004	$ 172,033	$ 3,593,882	4.8%	$ 3,421,849
2003	112,539	3,964,935	2.8%	3,852,396
2001	1,205,282	4,364,349	27.6%	3,159,067

Postretirement Medical Benefit Plan

In addition to pension benefits, the Board provides postretirement health care and life insurance benefits to all employees who retire with at least 30 years of service or at age 55 with at least 10 years of service. Currently, 384 retirees or surviving spouses of retired employees are covered under the plan. The life insurance benefit is a fixed amount of $5,000 per retiree. Health care coverage reimburses 80% of the amount of validated claims for certain medical, dental, vision and hospitalization costs.

GASB No. 12, *Disclosure of Information of Postemployment Benefits Other Than Pension Benefits by State and Local Government Employers*, discusses two methods for funding the above postretirement benefits. The method the Board continues to use is the "pay-as-you-go" method, resulting in recognized expenses in 2004 of approximately $1,135,000 for Electric System and $185,000 for the Water System ($2,006,000 and $310,000 in 2003, respectively).

The alternative method would accrue expenses as incurred and allow the Board to fund a portion of the future postemployment costs in advance on an actuarially determined basis. Under this method, the 2003 total expense, as determined by an actuarial study dated January 1, 2004, the date of the last valuation, for both the Electric System and Water System would have been approximately $4 million. The total actuarially determined health care liability for both systems as of January 1, 2004 was approximately $32.2 million. The unit credit funding method was used to compute the liability and assumes a 6% discount rate and a 12.5% annual rate of increase in the per capita cost of covered health care benefits for 2004. This rate is assumed to decrease gradually to 6% in the year 2017 and remain at that level thereafter. A 1% increase in the assumed health care cost trend could have a material effect on net postretirement health care costs.

12. Deferred Compensation

The Board offers all employees a deferred compensation plan created in accordance with Internal Revenue Code ("IRC") Section 457. The plan permits them to defer a portion of their salary until future years. Participation in the plan is optional and there is no employer matching. Payment from the plan is not available to employees until termination, retirement, death or unforeseeable emergency.

The Board works with separate investment providers who also provide third-party administration for all deferred compensation program funds. Participating employees have several investment options with varying degrees of market risk. The Board has no liability for losses under the plan, but does have the duty to administer the plan in a prudent manner.

The Board has little administrative involvement with the plan and does not perform the investing function. Therefore, in accordance with GASB No. 32, *Accounting and Financial Reporting for Internal Revenue Code Section 457 Deferred Compensation Plans*, the plan assets are not included in the accompanying balance sheet.

13. Trojan Project Fund (as restated)

Summary of Significant Accounting Policies

General

The Trojan Nuclear Plant ("Trojan"), a nonoperating facility, is jointly owned by Portland General Electric Company ("PGE"), 67.5%; the City of Eugene, acting by and through the Board, 30.0%; and Pacific Power & Light Company, 2.5%; as tenants in common. Trojan ceased commercial operation in 1993 and is being decommissioned. The Trojan Project financial statements reflect the Board's 30% ownership of Trojan.

Under the terms of Net Billing Agreements, executed in 1970, BPA is obligated to pay the Board amounts sufficient to pay all of the Board's costs related to the Project, including decommissioning and debt service notwithstanding the termination of plant output. BPA pays those costs primarily by issuing credits against the Net Billing Participant's purchases of electricity from BPA, but in some cases also makes payments in cash. The Board is required to transfer from its Electric System Fund to the Trojan Project Fund an amount equal to all net billing credits received through this agreement. The Board is then responsible for making payments from the Trojan Project Fund to the Trojan Project for the Board's share of decommissioning costs.

Since BPA is obligated to pay the Board's share of all Trojan Project costs, and has provided the Board with legally binding written assurances of its commitment to that obligation, the Board does not expect the closure and decommissioning of the Trojan Project to have any adverse effect on the Board's Electric or Water System. All Trojan related costs are expected to be born fully by BPA; however, as a function of the Board's minority ownership of the Trojan Project, Trojan costs would the legal obligation of the Board. The Board believes the circumstances where it would pay these costs without full reimbursement by BPA have a very low probability of occurring.

The Nuclear Regulatory Commission ("NRC") regulates the licensing, construction, operations and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to the Trojan operating license, allowing the Project to own the reactor and nuclear fuel but not to operate the facility. This license amendment eliminates certain operating requirements that are unnecessary for a permanently shutdown and de-fueled reactor. Trojan will continue to be subject to NRC regulation until it is fully decommissioned, all nuclear fuel is removed from the site to a U.S. Department of Energy ("USDOE") facility, and its license is terminated. The Board has also recorded a provision for decommissioning costs based on an estimate in current dollars and a receivable from BPA representing BPA's responsibility to pay for all Trojan costs. Any future change in the estimates for these costs will result in a change to the receivable from BPA under Net Billing Agreements.

The Board's costs related to administration of the Trojan Fund also are fully reimbursable by BPA.

Debt associated with Trojan Project activity is secured solely by a pledge of the receipts from Trojan Project fees and charges associated with the Two-Party Net Billing Agreement with BPA; therefore, the Trojan Project is reported as a proprietary fund.

Deferred Charges on Long-Term Debt

The Board has recorded deferred charges of $20,670 and $28,170 for certain Trojan bond issuance costs as of December 31, 2004 and 2003, respectively. Debt premium, discount, expenses and advance refunding costs are being amortized over the terms of the respective debt issues.

Asset Retirement Obligation

The Board adopted SFAS No. 143 on January 1, 2003. SFAS No. 143, *Accounting for Obligations Associated with the Retirement of Long-Lived Assets*, requires the recognition of asset retirement obligations ("ARO"), measured at estimated fair value, for legal obligations related to 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 ARO's that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are normally recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. In the case of Trojan, the amount of the ARO is included in the long-term receivable amount due from BPA. Interest is accreted annually on the ARO liability until the point it is settled. Accretion of interest, also, will increase the amount due from BPA over time. The estimated liability and amount due from BPA will be adjusted by any future revisions to the projected cost of decommissioning.

The ARO associated with the Trojan plant was recorded on a nominal dollar basis at the time of its abandonment in 1993, with costs to be recovered from BPA recorded as a long-term receivable. With the adoption of SFAS No. 143, the receivable from BPA and the related ARO for the Trojan plant were reduced by $24.4 million to adjust the balances to an estimated fair value as required by SFAS No. 143 of $59.7 million at January 1, 2003. Accordingly, the adoption of SFAS No. 143 did result in a cumulative effect adjustment in the statement of revenues, expenses and changes in fund net assets.

The following presents the 2004 and 2003 balances and activities in the ARO:

	2004	2003
Beginning balance	$ 46,477,000	$ 84,055,251
Impact of FAS 143 adoption	-	(24,444,444)
Expenditures	(8,895,873)	(14,911,585)
Accretion	2,848,819	2,222,222
Revision	815,213	(444,444)
Ending balance	$ 41,245,159	$ 46,477,000

Long-Term Receivable – BPA

The accumulated excess of expenses over net billings is reflected in the Balance Sheet as an increase to "Long-term receivable, BPA, net." Following is an analysis of changes in this account during 2004 and 2003:

	2004	2003
Adoption of SFAS No. 143		
Transition adjustment	$ -	$ (24,444,444)
Net accretion and revisions	3,664,032	1,777,778
Decommissioning and maintenance costs	8,722,292	12,637,831
Interest expense	3,393,674	3,826,063
Provision for decommissioning costs	(8,895,873)	(14,911,585)
Less		
Total net billings	(20,178,527)	(14,461,233)
Interest income	(373,889)	(423,762)
Decrease in receivable	(13,668,291)	(35,999,352)
Beginning balance	75,607,606	111,606,958
Ending balance	$ 61,939,315	$ 75,607,606

Cash and Investments

The Board maintains cash and investments in several fund accounts in accordance with bond resolutions and Board authorization. Descriptions of these fund account types are as follows:

Bond Funds

Used to account for legally restricted cash and investments for the purpose of reserving funds for making principal and interest payments on long-term debt if funds held in segregated cash and investments are deficient.

Reserve and Contingency Fund

Used to account for legally restricted cash for the purpose of making up any deficiencies in the Trojan Project Bond Funds. For purposes of the statement of cash flows, the fund is reflected as cash flow from investing activity in the amount of $2,001,065 in 2004.

Decommissioning Fund

Used to account for restricted cash and investments for the payment of decommissioning costs related to the Trojan Project.

Investments for Debt Service
Used to account for cash and investments, which are legally designated for payment of principal and interest on debt.

Deposits with financial institutions are comprised of bank demand deposits and savings accounts. The total bank balances, as recorded in the bank records at December 31, 2004 are $2,157,891 ($1,865 at December 31, 2003), of which all was covered by federal depository insurance.

The Trojan Project Fund's investments during the year included obligations of the U.S. Government, all of which are authorized by State Statutes and bond resolutions. Investments are categorized to give an indication of the level of risk assumed at year end. Category 1 includes investments that are insured or registered or for which the securities are held by the Trojan Project Fund or its agent in the Trojan Project Fund's name. Category 2 includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in the Trojan Project Fund's name. Category 3 includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent but not in the Trojan Project Fund's name. The Trojan Project Fund's investments are held in safekeeping in book entry form by the financial institution counterparty and are considered to be Category 3 investments under the above criteria. The Trojan Project Fund's investment in the State of Oregon Local Government Investment Pool ("LGIP") is not required to be categorized by level or risk because this investment is not evidenced by securities.

Investments, except for the investment in LGIP, are carried at fair value as required by GASB Statement No. 31, *Accounting and Financial Reporting for Certain Investments and for External Investment Pools*, using quoted market prices in 2004 and 2003. Also, as allowed by GASB Statement No. 31, the investment in LGIP is carried at amortized cost, which approximates fair value at December 31, 2004 and 2003.

Cash and investments consist of the following at December 31:

	2004		
	Restricted Cash and Investments	Cash and Cash Equivalents	Total Carrying Amount
Cash in bank demand deposits	$ -	$ 2,157,891	$ 2,157,891
Cash in other funds	2,001,861	-	2,001,861
Investment - direct obligation of U.S. government	14,092,243	-	14,092,243
Investments in the State of Oregon Local Government Investment Pool	-	4,994,260	4,994,260
	$ 16,094,104	$ 7,152,151	$ 23,246,255

	2003		
	Restricted Cash and Investments	Cash and Cash Equivalents	Total Carrying Amount
Cash in bank demand deposits	$ -	$ 1,865	$ 1,865
Cash in other funds	8,155	-	8,155
Investment - direct obligation of U.S. government	16,079,303	4,896,167	20,975,470
Investments in the State of Oregon Local Government Investment Pool	-	1,346,033	1,346,033
	$ 16,087,458	$ 6,244,065	$ 22,331,523

Long-Term Debt – Bonds Payable
Bonds are payable as to principle and interest solely from the revenues of the Trojan Project Fund. The revenues primarily include payments to the Board pursuant to Net Billing Agreements.

	2004	2003
Long-term portion of bonds payable		
Trojan Nuclear Project Revenue Bonds, Series 1997, term bonds, 5.90%, due through 2009	$ 36,670,000	$ 44,600,000
Less unamortized discount	110,826	154,386
Less unamortized refunding costs	1,943,485	2,360,269
	$ 34,615,689	$ 42,085,345

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Trojan Project bonds payable, including current and long-term	$ 44,600,000	$ 45,046,000	$ 49,570,345	$ 52,463,658

Total principal requirements reflective of the foregoing bonds, during the years 2004 through 2008 and thereafter are as follows:

2005	$ 7,930,000
2006	8,395,000
2007	8,890,000
2008	9,415,000
Thereafter	9,970,000
	$ 44,600,000

The resolutions authorizing the issuance of revenue bonds contain various covenants and obligations with which the Board must comply.

Commitments and Contingencies
BPA
The Board has evaluated its long-term receivable from BPA and deems it fully collectible based on BPA's ability to set rates as a federal electric power marketing agency.

Environmental Matters
Trojan is engaged in environmental investigation and remediation efforts in its ordinary course of business. The Board has considered these matters when estimating the decommissioning liability to be paid from the fund. In the opinion of management, the ultimate outcome of these matters will not have a material effect on the Board's financial position beyond amounts already accrued as of December 31, 2004. As such, amounts will be paid by BPA.

14. Commitments and Contingencies

Water Projects
At December 31, 2004, the Board had a contractual commitment related to its Hayden Bridge expansion project totaling $185,000. In addition, the Board had previously committed to long-term acquisition and construction of groundwater resources. However, there were no outstanding construction contracts for groundwater acquisition or construction at December 31, 2004.

Electric Re-Licensing Projects
To meet the requirements of a renewed license to operate Leaburg and Walterville hydroelectric facilities, the Board is constructing improvements for these integrated facilities. Approximately $4,500,300 is projected necessary to fulfill the license requirements through the year 2006, including approximately $1,000,000 for contractual commitments in place December 31, 2004 to be fulfilled in 2005. The majority of the contractual commitments are for operational equipment at Leaburg. Compliance studies and other improvements for the overall site of Walterville and Leaburg are targeted for 2005 to 2006.

The Board is in the application process of renewing its license to operate its Carmen Smith hydroelectric facility. Contracts totaling $4,011,851, executable by individual work orders, for environmental work and engineering are expected to continue into 2006. Contractual commitments for work orders outstanding at December 31, 2004 were approximately $825,000.

Self-Insurance
The Board is exposed to various risks of loss due to self-insured risks retention relating to general liability claims. General liability claims are generally limited to $100,000 for property damage claims and $1,000,000 for all other claims, per occurrence.

Claims liabilities recorded in the basic financial statements are based on the estimated ultimate loss and reserves for claims incurred as of the balance sheet date, adjusted from current trends through a case-by-case review of all claims, including incurred but not reported ("IBNR") claims. At December 31, 2004, a total claims liability of approximately $354,000 ($294,000 at December 31, 2003) is reported in the basic financial statements. All prior and current-year claims are fully reserved and have not been discounted.

		Liability Balance at Beginning of Year	Current Year Claims and Changes in Estimates	Claim Payments	Liability Balance at End of Year
2004	General liability	$ 293,960	$ 164,260	$ (103,950)	$ 354,270
2003	General liability	$ 131,162	$ 221,280	$ (58,482)	$ 293,960
2002	General liability	$ 87,344	$ 218,307	$ (174,489)	$ 131,162

Claims and Other Legal Proceedings
The Board was a party to litigation in the case of *Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement.* The litigation contended that various parties, including the Board, that bought and sold electric energy in the Pacific Northwest wholesale power markets during the California energy crisis charged unjust and/or unreasonable prices. Refund claims were asserted against the Board. The Board traded electricity in the Pacific Northwest wholesale market for the sole purpose of ensuring its customer's needs would be fulfilled at the best possible rates, since the Board's own generation and its contracts with BPA were insufficient to meet those needs. The Board contended that the prices it charged were neither unjust nor unreasonable, and further claimed that the Federal Energy Regulatory Commission ("FERC") did not have jurisdictional authority over a publicly owned utility such as the Board. On June 25, 2003, FERC issued its "Order Granting Rehearing, Denying Request to Withdraw Compliant and Terminating Proceeding" in which FERC terminated the litigation without ordering refunds from any parties. In addition, FERC concurred that it did not have regulatory jurisdiction over municipal utilities such as the Board. As of December 31, 2004, the litigation has been appealed to the United States Court of Appeals for the Ninth Circuit. The Board is unable to predict either the outcome of the appeal or estimate the potential liability in this proceeding.

The Board was also a party to litigation in the case of *San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Service Into markets Operated by the California Independent System Operator Corporation and the California Power Exchange*. The litigation contended that various parties that bought and sold electric energy in the wholesale power markets operated by the California Independent System Operator ("ISO") and the California Automated Power Exchange ("PX") during the California energy crisis charged unjust and/or unreasonable prices. The Board did not directly participate in the centralized power markets operated by the ISO or the PX, and therefore was not a party to initial FERC proceedings in this matter. However, the Board did sell approximately $500,000 of power to the ISO in December 2000 during system emergencies declared by the ISO.

The Board was issued a subpoena as a nonparty to the proceedings, but elected to file a Motion to Intervene in the case to fully protect its interests. The Board contended that the prices it charged were neither unjust nor unreasonable, and that it was not subject to and did not violate either the ISO or PX tariffs. A FERC-appointed Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability (Proposed Findings) showing a potential refund of $226,00 due from the Board to the ISO. However, the Proposed Findings also showed the ISO potentially owing the Board $483,000 for nonpayment of the transactions in question. Therefore, the Board appears to be in a net refund position with regard to the Proposed Findings. In March 2003 FERC issued an Order largely approving the Proposed Findings and subsequently issued other orders affirming its jurisdiction in this case as regards to municipal utilities selling to the ISO. As of December 31, 2004, the FERC orders have been appealed to the United States Court of Appeals for the Ninth Circuit. The Board is unable to predict either the outcome of the appeal or estimate the potential liability in this proceeding.

The Board is involved in various other litigation. In the opinion of management, the ultimate outcome of these claims will not have a material effect on the Board's financial position beyond amounts already accrued as of December 31, 2004.

Environmental Matters
The Board owns land near its headquarters, which is contaminated from a former manufactured gas facility. Under a participant agreement with other entities, the Board shares in 16-2/3% of the clean up costs. Based on a feasibility study conducted by environmental consultants and the Department of Environment Quality's stated preferences for similar contaminated sites, $666,400 was accrued as a liability at December 31, 2004 ($346,000 at December 31, 2003).

Refer to Note 13 for discussion of environmental matters related to Trojan Project.

Supplementary Information

Analysis of Certain Restricted Cash and Investments for Debt Service

Eugene Water & Electric Board
Electric System
Analysis of Certain Restricted Cash and Investments for Debt Service
December 31, 2004

	Bond Funds Debt Service Accounts	Construction Fund	Total All Funds
Ending balance - December 31, 2003	$ 7,551,594	$ 10,120,491	$ 17,672,085
Proceeds from bond issue			-
Deposits from general fund	15,218,000	984,208	16,202,208
Interest earnings	60,165	72,577	132,742
Receipts	15,278,165	1,056,785	16,334,950
Principal payments	4,645,000	-	4,645,000
Interest payments	11,267,273	-	11,267,273
Transfers to general fund	3,754	9,064,096	9,067,850
Disbursements	15,916,027	9,064,096	24,980,123
U.S. government securities, at market	6,913,732	-	6,913,732
State of Oregon Local Government Investment Pool	-	2,113,180	2,113,180
Ending balance - December 31, 2004	$ 6,913,732	$ 2,113,180	$ 9,026,912

Eugene Water & Electric Board
Water System
Analysis of Certain Restricted Cash and Investments for Debt Service
December 31, 2004

	Bond Fund Debt Service Accounts	Construction Fund	Total All Funds
Ending balance - December 31, 2003	$ 1,090,540	$ 8,677,696	$ 9,768,236
Deposits from general fund	2,545,700		2,545,700
Interest earnings	9,543	109,006	118,549
Receipts	2,555,243	109,006	2,664,249
Principal payments	825,000	-	825,000
Interest payments	1,746,789	-	1,746,789
Transfers to general fund	-	87,896	87,896
Disbursements	2,571,789	87,896	2,659,685
U.S. government securities, at market	1,073,994	7,960,036	9,034,030
State of Oregon Local Government Investment Pool	-	738,770	738,770
Ending balance - December 31, 2004	$ 1,073,994	$ 8,698,806	$ 9,772,800

Long-Term Bonded Debt and Interest Payment Requirements (Including Current Portion)

Eugene Water & Electric Board
Electric System
Long-Term Bonded Debt and Interest Payment Requirements, including Current Portion
December 31, 2004

	Revenue Bonds 1996 Series 12-1-96		Refunding Revenue Bonds 1997 Series 11-4-97		Refunding Revenue Bonds 1998 Series 2-1-98		Revenue Bonds 1998 Series A 11-15-98	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
2005	$ 890,000	$ 756,605	$ 1,065,000	$ 407,225	$ 55,000	$ 1,664,813	$ 315,000	$ 717,313
2006	930,000	713,885	1,115,000	359,833	345,000	1,662,475	335,000	699,327
2007	975,000	668,315	1,165,000	309,658	435,000	1,647,640	355,000	679,696
2008	1,025,000	619,565	1,225,000	256,650	540,000	1,625,455	375,000	658,857
2009	1,080,000	567,290	1,285,000	199,075	650,000	1,597,915	400,000	636,657
2010	1,135,000	511,130	1,355,000	137,395	770,000	1,568,655	420,000	612,777
2011	1,195,000	450,975	1,420,000	71,000	895,000	1,533,245	450,000	586,653
2012	1,260,000	386,744			1,035,000	1,491,180	475,000	558,663
2013	1,325,000	319,019			1,190,000	1,442,018	505,000	529,118
2014	1,395,000	247,800			1,765,000	1,384,898	535,000	497,707
2015	1,475,000	169,680			2,030,000	1,300,178	570,000	464,430
2016	1,555,000	87,080			2,315,000	1,201,723	610,000	425,385
2017					2,635,000	1,085,973	650,000	383,600
2018					2,980,000	954,223	695,000	339,075
2019					3,350,000	805,223	740,000	291,468
2020					3,750,000	636,048	795,000	240,778
2021					4,190,000	446,673	850,000	186,320
2022					4,655,000	235,070	905,000	128,095
2023							965,000	66,099
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
	14,240,000	5,498,088	8,630,000	1,740,836	33,585,000	22,283,405	10,945,000	8,702,018
Less current	890,000	-	1,065,000	-	55,000	-	315,000	-
	$ 13,350,000	$ 5,498,088	$ 7,565,000	$ 1,740,836	$ 33,530,000	$ 22,283,405	$ 10,630,000	$ 8,702,018

Eugene Water & Electric Board
Electric System
Long-Term Bonded Debt and Interest Payment Requirements, including Current Portion
December 31, 2004

	Revenue Bonds 2001A Series Curent Interest 11-15-01		Revenue Bonds 2001 B Series 11-15-01		Refunding Revenue Bonds 2002 A Series 5-7-02		Revenue Bonds 2002 B Series 5-22-02	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
2005	$ 90,000	$ 1,638,776	$ 760,000	$ 1,932,363	$ 1,210,000	$ 525,525	$ 1,045,000	$ 540,523
2006	180,000	1,633,088	790,000	1,901,963	1,280,000	462,000	1,090,000	494,804
2007	260,000	1,621,712	820,000	1,870,363	1,350,000	394,800	1,145,000	441,666
2008	390,000	1,605,280	855,000	1,837,563	1,425,000	323,925	1,200,000	383,271
2009	510,000	1,580,632	890,000	1,803,363	1,500,000	249,113	1,265,000	320,871
2010	645,000	1,548,400	925,000	1,767,763	1,575,000	170,363	1,335,000	248,766
2011	790,000	1,507,636	960,000	1,730,763	1,670,000	87,675	1,415,000	171,336
2012	950,000	1,457,708	1,000,000	1,692,363			1,495,000	88,205
2013	1,125,000	1,397,668	1,040,000	1,652,363				
2014	1,310,000	1,326,568	1,095,000	1,597,763				
2015	1,520,000	1,243,776	1,155,000	1,540,275				
2016	1,745,000	1,147,712	1,215,000	1,479,638				
2017	1,990,000	1,037,428	1,275,000	1,415,850				
2018	2,255,000	911,660	1,345,000	1,348,913				
2019	2,545,000	769,144	1,415,000	1,278,300				
2020	2,860,000	608,300	1,490,000	1,204,013				
2021	3,200,000	427,548	1,565,000	1,125,788				
2022	3,565,000	225,308	1,650,000	1,043,625				
2023	867,106	3,097,894	1,735,000	957,000				
2024	839,611	3,305,389	1,825,000	870,250				
2025	814,720	3,520,280	1,915,000	779,000				
2026	789,579	3,740,421	2,010,000	683,250				
2027	756,540	3,913,460	2,110,000	582,750				
2028			2,215,000	477,250				
2029			2,325,000	366,500				
2030			2,440,000	250,250				
2031			2,565,000	128,250				
	29,997,556	39,265,788	39,385,000	33,317,532	10,010,000	2,213,401	9,990,000	2,689,442
Less current	90,000	-	760,000	-	1,210,000	-	1,045,000	-
	$ 29,907,556	$ 39,265,788	$ 38,625,000	$ 33,317,532	$ 8,800,000	$ 2,213,401	$ 8,945,000	$ 2,689,442

Eugene Water & Electric Board
Electric System
Long-Term Bonded Debt and Interest Payment Requirements, including Current Portion
December 31, 2004

	Revenue and Refunding 2002 C Series 5-22-02		Revenue and Refunding 2003 Series 6-10-03		Total Electric System Payments		
	Principal	Interest	Principal	Interest	Principal	Interest	Totals
2005	$ 465,000	$ 527,983	$ 250,000	$ 1,778,287	$ 6,145,000	$ 10,489,413	$ 16,634,413
2006	475,000	514,963	995,000	1,773,288	7,535,000	10,215,626	17,750,626
2007	495,000	500,119	1,710,000	1,753,387	8,710,000	9,887,356	18,597,356
2008	505,000	483,289	1,770,000	1,702,088	9,310,000	9,495,943	18,805,943
2009	530,000	464,351	1,830,000	1,648,987	9,940,000	9,068,254	19,008,254
2010	550,000	443,681	1,890,000	1,594,088	10,600,000	8,603,018	19,203,018
2011	575,000	420,994	1,950,000	1,537,387	11,320,000	8,097,664	19,417,664
2012	600,000	396,556	2,035,000	1,459,388	8,850,000	7,530,807	16,380,807
2013	620,000	370,756	2,125,000	1,377,987	7,930,000	7,088,929	15,018,929
2014	650,000	343,476	2,200,000	1,292,988	8,950,000	6,691,200	15,641,200
2015	680,000	314,226	2,315,000	1,182,987	9,745,000	6,215,552	15,960,552
2016	710,000	282,776	2,435,000	1,067,238	10,585,000	5,691,552	16,276,552
2017	740,000	249,051	2,565,000	945,487	9,855,000	5,117,389	14,972,389
2018	775,000	213,531	2,695,000	817,238	10,745,000	4,584,640	15,329,640
2019	815,000	175,750	2,835,000	682,487	11,700,000	4,002,372	15,702,372
2020	855,000	135,000	2,985,000	540,738	12,735,000	3,364,877	16,099,877
2021	900,000	92,250	3,140,000	391,487	13,845,000	2,670,066	16,515,066
2022	945,000	47,250	3,300,000	234,488	15,020,000	1,913,836	16,933,836
2023			1,635,000	69,488	5,202,106	4,190,481	9,392,587
2024					2,664,611	4,175,639	6,840,250
2025					2,729,720	4,299,280	7,029,000
2026					2,799,579	4,423,671	7,223,250
2027					2,866,540	4,496,210	7,362,750
2028					2,215,000	477,250	2,692,250
2029					2,325,000	366,500	2,691,500
2030					2,440,000	250,250	2,690,250
2031					2,565,000	128,250	2,693,250
	11,885,000	5,976,002	40,660,000	21,849,513	209,327,556	143,536,025	352,863,581
Less current	465,000	-	250,000	-	6,145,000	-	6,145,000
	$ 11,420,000	$ 5,976,002	$ 40,410,000	$ 21,849,513	$ 203,182,556	$ 143,536,025	$ 346,718,581

Eugene Water & Electric Board
Water System
Long-Term Bonded Debt and Interest Payment Requirements, including Current Portion
December 31, 2004

	Revenue Bonds Refunding 1997 Series 11-4-97		Revenue Bonds 2000 Series 1-1-00		Revenue Bonds 2002 Series 7-16-02		Total Water System Payments		
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest	Totals
2005	$ 860,000	$ 79,878	$ -	$ 1,224,098	$ -	$ 406,101	$ 860,000	$ 1,710,077	$ 2,570,077
2006	905,000	41,178	-	1,224,098	-	406,101	905,000	1,671,377	2,576,377
2007			450,000	1,224,098	460,000	406,101	910,000	1,630,199	2,540,199
2008			470,000	1,200,698	470,000	393,451	940,000	1,594,149	2,534,149
2009			495,000	1,176,023	490,000	378,764	985,000	1,554,787	2,539,787
2010			520,000	1,149,788	505,000	362,839	1,025,000	1,512,627	2,537,627
2011			550,000	1,122,228	525,000	345,164	1,075,000	1,467,392	2,542,392
2012			580,000	1,092,083	545,000	326,264	1,125,000	1,418,347	2,543,347
2013			610,000	1,061,483	570,000	305,826	1,180,000	1,367,309	2,547,309
2014			645,000	1,027,933	595,000	283,596	1,240,000	1,311,529	2,551,529
2015			680,000	992,135	620,000	259,796	1,300,000	1,251,931	2,551,931
2016			720,000	954,055	645,000	234,221	1,365,000	1,188,276	2,553,276
2017			760,000	913,555	675,000	206,809	1,435,000	1,120,364	2,555,364
2018			800,000	870,615	710,000	178,121	1,510,000	1,048,736	2,558,736
2019			845,000	825,015	740,000	147,059	1,585,000	972,074	2,557,074
2020			895,000	776,428	780,000	113,759	1,675,000	890,187	2,565,187
2021			950,000	724,518	815,000	77,879	1,765,000	802,397	2,567,397
2022			1,005,000	669,418	855,000	40,185	1,860,000	709,603	2,569,603
2023			1,060,000	611,128			1,060,000	611,128	1,671,128
2024			1,120,000	549,648			1,120,000	549,648	1,669,648
2025			1,185,000	484,688			1,185,000	484,688	1,669,688
2026			1,255,000	415,069			1,255,000	415,069	1,670,069
2027			1,330,000	341,338			1,330,000	341,338	1,671,338
2028			1,410,000	263,200			1,410,000	263,200	1,673,200
2029			1,490,000	180,363			1,490,000	180,363	1,670,363
2030			1,580,000	92,825			1,580,000	92,825	1,672,825
	1,765,000	121,056	21,405,000	21,166,528	10,000,000	4,872,036	33,170,000	26,159,620	59,329,620
Less current	860,000	-	-	-	-	-	860,000	-	860,000
	$ 905,000	$ 121,056	$ 21,405,000	$ 21,166,528	$ 10,000,000	$ 4,872,036	$ 32,310,000	$ 26,159,620	$ 58,469,620

Schedule of Bonded Debt
(Including Current Portion) Transactions

Eugene Water & Electric Board
Electric System
Schedule of Bonded Debt (Including Current Portion) Transactions
December 31, 2004

	Principal				Interest			
	Outstanding January 1, 2004	Issued During Year	Matured During Year	Outstanding December 31, 2004	Outstanding January 1, 2004	Matured During Year	Reedeemed During Year	Outstanding December 31, 2004
Electric Revenue Bonds, with interest rates from 3.90% to 6.705, maturing through 2031 (original issue $190,230,000)	$ 76,890,000	$ -	$ (2,330,000)	$ 74,560,000	$ 1,823,103	$ 4,195,859	$ (4,374,460)	$ 1,644,502
Electric Revenue Refunding Bonds, with interest rates from 2.0% to 5.25%, maturing through 2022 (original issue $127,190,000)	107,085,000	-	(2,315,000)	104,770,000	2,189,183	5,108,121	(5,254,038)	2,043,266
Electric Revenue Current Interest Bonds, with interest rate of 6.23%, maturing through 2027 (original issue $29,997,556)	29,997,556	-	-	29,997,556	682,823	1,638,776	(1,638,776)	682,823
Total Electric System	$ 213,972,556	$ -	$ (4,645,000)	$ 209,327,556	$ 4,695,109	$ 10,942,756	$ (11,267,274)	$ 4,370,591

Eugene Water & Electric Board
Water System
Schedule of Bonded Debt (Including Current Portion) Transactions
December 31, 2004

	Principal				Interest			
	Outstanding January 1, 2004	Issued During Year	Matured During Year	Outstanding December 31, 2004	Outstanding January 1, 2004	Matured During Year	Redeemed During Year	Outstanding December 31, 2004
Water Revenue Refunding Bonds, with interest rates from 4.45% to 4.55%, maturing through 2006 (original issue $6,615,000)	$ 2,590,000	$ -	$ (825,000)	$ 1,765,000	$ 48,580	$ 101,293	$ (116,590)	$ 33,283
Water Revenue Bonds, with interest rates from 2.75% to 5.875%, maturing through 2030 (original issue $31,405,000)	31,405,000	-	-	31,405,000	679,250	1,630,199	(1,630,198)	679,251
Total Water System	$ 33,995,000	$ -	$ (825,000)	$ 33,170,000	$ 727,830	$ 1,731,492	$ (1,746,788)	$ 712,534

APPENDIX E

PROPOSED FORMS OF OPINIONS OF BOND COUNSEL

Opinion with respect to the Series 2005 Bonds

_______, 2005

Eugene Water & Electric Board
500 East 4th Avenue
Eugene, Oregon 97401

Dear Sirs:

CITY OF EUGENE, OREGON, TROJAN PROJECT
REVENUE BONDS, REFUNDING SERIES 2005
$26,640,000

At your request we have examined into the validity of $26,640,000 Trojan Project Revenue Bonds, Refunding Series 2005 (the "Bonds"), of the City of Eugene, Oregon (the "City"). The Series 2005 Bonds are issuable in fully registered form without coupons, in the denominations of $5,000, or multiples thereof, are dated the date of issuance thereof, mature on September 1 in each of the years and in the amounts and bear interest payable on March 1 and September 1 of each year beginning September 1, 2005 at the rates per annum, as follows:

Year	Amount	Interest Rate
2005	$3,205,000	3.00%
2006	7,435,000	5.00
2007	7,805,000	5.00
2008	8,195,000	5.00

The Bonds are not subject to redemption prior to maturity. The Bonds recite that they are issued under and pursuant to resolutions adopted by the Eugene Water & Electric Board on September 21, 2004 (collectively, the "Bond Resolution"), and under the authority of and in full compliance with the Constitution and statutes of the State of Oregon, and the Charter of the City for the purpose of refunding, together with other available funds, all the City's outstanding Trojan Project Revenue Bonds, Series of 1977.

We have examined the Constitution and statutes of the State of Oregon, the Charter of the City certified copies of proceedings of the Council of the City and the Eugene Water & Electric Board authorizing the issuance of the Bonds, and such other records, certificates and other documents as we have considered necessary or appropriate for the purposes of this opinion. We have also examined an executed Series 2005 Bond.

In our opinion, the Bond Resolution has been duly adopted, and the provisions thereof are valid and binding upon the City; the Bonds have been duly authorized and issued in accordance with the Constitution, the Charter of the City and statutes of the State of Oregon, and constitute valid and legally binding obligations of the City payable solely from and secured by a pledge of and lien on the Revenues, subject to the payment of Project Expenses, as such terms are defined in the Bond Resolution, and the holders of the Bonds are entitled to the security and benefits of the Bond Resolution.

It is to be understood that the rights of the holders of the Bonds under the same and under the Bond Resolution and the enforceability thereof under the same may be subject to general principles of equity which permit the exercise of judicial discretion and to valid bankruptcy, insolvency, reorganization, moratorium and other laws for the relief of debtors.

We undertake no responsibility for the accuracy, completeness or fairness of any official statement or other offering materials relating to the Bonds and express herein no opinion relating thereto.

Very truly yours,

HAWKINS DELAFIELD & WOOD LLP

FORM OF OPINION AS TO NET BILLING AGREEMENTS

_______________, 2005

Eugene Water & Electric Board
500 East 4th Avenue
Eugene, Oregon 97440

Dear Sirs:

We have acted as bond counsel to the Eugene Water & Electric Board (the "Board") in connection with the issuance of $26,640,000 aggregate principal amount of Trojan Project Revenue Bonds, Refunding Series 2005 (the "Bonds") of the City of Eugene, Oregon (the "City").

In connection with the issuance of the Bonds, the Board has requested that we examine into the validity of the Trojan Nuclear Project Agreement between the United States of America, Department of the Interior, acting by and through the Bonneville Power Administrator (the "Administrator"), and the City, dated October 5, 1970 (the "Two Party Net Billing Agreement"), and the Trojan Nuclear Project Agreements dated October 5, 1970, each of which is among the United States of America, Department of the Interior, acting by and through the Administrator, the City and one of the following: Blachly-Lane County Cooperative Electric Association; City of Canby, Oregon; Clatskanie Peoples' Utility District; Consumers Power, Inc.; City of Forest Grove, Oregon; Lincoln Electric Cooperative (Washington); City of McMinnville, Oregon; City of Monmouth, Oregon; Northern Wasco Peoples' Utility District; Salem Electric; City of Springfield, Oregon; Umatilla Electric Cooperative Association; and West Oregon Electric Cooperative (collectively, the "Trojan Project Participants" and all such Agreements, the "Net Billing Agreements"), and the letter agreement dated __________, 2005, between the Bonneville Power Administration ("Bonneville") and the City (the "2005 Letter Agreement").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State of Oregon, the Charter of the City and such statutes as we deemed relevant to this opinion;

(b) The Constitution of the United States of America and such federal statutes and regulations as we deemed relevant to this opinion;

(c) Executed or certified copies of the Net Billing Agreements and the 2005 Letter Agreement;

(d) The Certificate of the General Manager of the Board, dated the date hereof, certifying that, except as described in the Official Statement for the Bonds dated April 7, 2005 (the "Official Statement"), (i) neither the City nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the 2005 Letter Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(e) The Certificate of the Administrator, dated the date hereof, certifying that, except as described in the Official Statement, (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the 2005 Letter Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) Certified copies of the proceedings of the Board authorizing the execution and delivery of the Net Billing Agreements and the 2005 Letter Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(g) The respective opinions of counsel for each of the Trojan Project Participants (collectively, the "Local Counsel Opinions"), rendered in 1971, to the effect that, inter alia, the Net Billing Agreement to which such Participant is a party was duly authorized, executed and delivered by such Participant and did not constitute a violation of or conflict with the provisions of applicable law or the terms and conditions of any agreement by which such Participant is bound;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, inter alia, (i) the office of Administrator was duly established and is validly existing, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the 2005 Letter Agreement and (iii) each of the Net Billing Agreements and the 2005 Letter Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in City of Springfield v. Washington Public Power Supply System, et al., 752 F.2d 1423 (9th Cir. 1985), cert. denied, 474 U.S. 1055 (1986); and

(j) Such other documents, agreements, proceedings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon, we are of the opinion that each of the Net Billing Agreements is a legal and valid obligation of each of the parties thereto, enforceable against such parties in accordance with its terms, and that the 2005 Letter Agreement is a legal and valid obligation of the City, enforceable against the City in accordance with its terms; provided, however, that the enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the General Manager of the Board and the Administrator referred to above in paragraphs (d) and (e); (3) the due incorporation and valid existence of each of the Trojan Project Participants; and (4) the correctness, as of its date and the date hereof, of each Local Counsel Opinion referred to above in paragraph (g) as to (A) the due authorization, execution and delivery by the Trojan Project Participant represented by such counsel of the Net Billing Agreement to which such Participant is a party and (B) no violation of or conflict with the provisions of applicable law or any agreement; and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

Very truly yours,

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APPENDIX F

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL

__________, 2005

City of Eugene, Oregon
c/o Eugene Water & Electric Board
Eugene, Oregon 97440
Re: City of Eugene, Oregon,

$26,640,000 Trojan Project Revenue Bonds, Refunding Series 2005

Ladies and Gentlemen:

We have acted as Special Tax Counsel in connection with the issuance by the City of Eugene, Oregon (the "City") acting by and through the Eugene Water & Electric Board (the "Board") of $26,640,000 aggregate principal amount of Trojan Project Revenue Bonds, Refunding Series 2005 (Tax-exempt) (the "Series 2005 Bonds"). The Series 2005 Bonds are to be issued pursuant to the Charter of the City, Oregon Revised Statutes, a Resolution authorizing the issuance of Trojan Project Revenue Bonds (the "Resolution") and a First Supplemental Resolution authorizing the Series 2005 Bonds (the "First Supplemental Resolution" and, together with the Resolution, the "Resolutions"). The Series 2005 Bonds are being issued for the purpose of refunding all of the City's outstanding Trojan Project Revenue Bonds, Series of 1977.

In such connection, we have reviewed certified copies of the Resolutions; the Tax Matters Certificate executed and delivered by the City, acting by and through the Board, on the date hereof and the Tax Matters Certificate executed and delivered on the date hereof by the Bonneville Power Administration (collectively, the "Tax Certificates"); the opinion of Hawkins Delafield & Wood LLP, as Bond Counsel; additional certificates of the City, the Board, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

Certain agreements, requirements and procedures contained or referred to in the Resolutions, the Tax Certificates and other relevant documents may be changed and certain actions (including, without limitation, defeasance of Series 2005 Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. No opinion is expressed herein as to any Series 2005 Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice or approval of counsel other than ourselves.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Our engagement with respect to the Series 2005 Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolutions and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Series 2005 Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2005 Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against the City and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of the City, dated April 7, 2005, relating to the Series 2005 Bonds, other than the first paragraph on the cover thereof and the portion titled "TAX MATTERS", or other offering material relating to those Bonds and express no opinion with respect thereto.

We have relied with your consent on the opinion of Hawkins Delafield & Wood LLP, Bond Counsel, with respect to the validity, due authorization and issuance of the Series 2005 Bonds.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the opinion that interest on the Series 2005 Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "Act") and Section 103 of the Internal Revenue Code of 1986 (the "Code") and is excluded from State of Oregon and Multnomah County, Oregon personal income taxes. Interest on the Series 2005 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

Except as expressly stated herein, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2005 Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

DEFINITIONS OF CERTAIN TERMS USED IN THIS OFFICIAL STATEMENT

Summarized below are definitions of certain words and terms appearing in this Official Statement. Any documents referred to in the following definitions include any modifications, amendments or supplements thereto from time to time made in accordance with the provisions of such documents. Words and terms that are capitalized in this Official Statement, whether or not defined below or elsewhere herein, are qualified by reference to the meanings assigned to them in the documents in which they appear.

"Accountant" means an independent certified public accountant (or a firm thereof) of recognized standing, selected by the Board and may be the accountant regularly auditing the books of the Board.

"Authorized Representative" means the President, Vice President, Secretary, Assistant Secretary, General Manager or Director, Financial Services Division, of the Board, each of which shall be an authorized officer of the Board for the purposes of the Resolution, or such other person or persons so designated by resolution of the Board.

"Board" means the Eugene Water & Electric Board, or, if said Board shall be abolished, the board, body, commission or agency succeeding to the principal functions thereof or to whom the powers and duties granted or imposed by the Resolution shall be given by any law, including the Charter of the City, or any ordinance or resolution of the Common Council thereof.

"Bond" or **"Bonds"** means all bonds, notes or other evidences of indebtedness authenticated and delivered pursuant to the Resolution.

"Bond Counsel's Opinion" or **"Opinion of Bond Counsel"** means an opinion signed by any attorney or firm of attorneys of nationally recognized standing in the field of law relating to revenue bonds of municipalities and public agencies, selected by the Board.

"Bond Fund Trustee" means Wells Fargo Bank, National Association, its successor or successors and any substitute Bond Fund Trustee appointed pursuant to the Resolution.

"Bondholder", **"Owner"** or **"Holder"** or words of similar import means, when used with reference to a Bond, the person in whose name the Bond is registered on the registry books kept by the Bond Fund Trustee pursuant to the Resolution.

"Electric System" means the electric utility properties, assets and rights, real and personal, tangible and intangible, now owned by the Board, and all properties and assets constructed or acquired as renewals, replacements, additions, improvements and betterments to and extensions of such properties and assets, including facilities for the generation, transmission and distribution of electric power and energy and the production, transmission and distribution of steam, but shall not include the City's Ownership Share of the Trojan Project, or any electric utility properties, assets and rights, real and personal, tangible and intangible, hereafter constructed or acquired by the Board as a separate utility system, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire any such separate utility system. (The Electric System is referred to in the Resolution as the "Distribution Division.")

“Electric System Revenue Fund” means the Distribution Division General Fund held in trust and administered by the Board, which is continued for the purposes of the Resolution and the Electric System Resolution.

“Electric System Resolution” means the resolution of the Board entitled “A RESOLUTION AUTHORIZING AND PROVIDING FOR THE ISSUANCE OF REVENUE BONDS OF THE CITY OF EUGENE, OREGON FOR THE PURPOSES OF THE ELECTRIC SYSTEM OF SAID CITY; COVENANTING AS TO ESTABLISHMENT, MAINTENANCE, REVISION AND COLLECTION OF CHARGES AND RATES FOR THE USE AND SERVICES OF SAID ELECTRIC SYSTEM AND THE COLLECTION AND DISBURSEMENT OF THE REVENUES DERIVED THEREFROM; PLEDGING THE REVENUES FROM SAID ELECTRIC SYSTEM TO THE PAYMENT OF THE PRINCIPAL AND INTEREST OF SAID BONDS AS THE SAME FALL DUE; CREATING CERTAIN FUNDS; SETTING FORTH THE LIMITATIONS OR CONDITIONS UPON THE ISSUANCE BY THE CITY OF ADDITIONAL BONDS PAYABLE FROM THE AFORESAID REVENUES; MAKING OTHER COVENANTS AND AGREEMENTS IN CONNECTION WITH THE FOREGOING AND REPEALING ALL RESOLUTIONS OR PARTS OF RESOLUTIONS IN CONFLICT WITH THIS RESOLUTION” adopted June 16, 1986, as supplemented and amended.

“Event of Default” means any event specified under Appendix H — “SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — EVENT OF DEFAULT.”

“Investment Securities” means and include any securities, if and to the extent the same are at the time legal investments by the Board of the funds to be invested therein and conform to the policies set forth in any investment guidelines adopted by the Board and in effect at the time of the making of such investment.

“Net Billing Agreements” means the Two-Party Net Billing Agreement and the Three-Party Net Billing Agreements.

“Operating Expenses of the Electric System” means the costs and expense of operating and maintaining the Electric System. (The Operating Expenses of the Electric System are referred to in the Resolution as the “Operating Expenses of the Distribution Division.”)

“Outstanding” means, as of any date, all Bonds theretofore or thereupon being authenticated and delivered under the Resolution except:

(i) any Bonds canceled by the Bond Fund Trustee at or prior to such date;

(ii) any Bonds the principal and premium, if any, of and interest on which have been paid in accordance with the terms thereof;

(iii) any Bonds in lieu of or in substitution for which other Bonds have been authenticated and delivered pursuant to the Resolution; and

(iv) any Bonds deemed to have been paid as provided in Appendix H — “SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — Defeasance.”

“Participant’s Share” means the decimal fraction share of Project capability of each Participant as such share may be adjusted pursuant to the Net Billing Agreements.

“Prior Resolution” means the resolution adopted by the Board on June 23, 1971, providing for the issuance of Trojan Nuclear Project Revenue Bonds, as amended.

"Project Expenses" means all of the Board's costs resulting from the City's ownership of an interest in the Trojan Project, the operation and maintenance of and renewals and replacements to the Trojan Project and the salvage, discontinuance, decommissioning, dismantling and disposition thereof, but excluding amounts which the Board is required to pay in each year into the Trojan Bond Fund or to otherwise set aside for the payment of the Project Bonds (as defined in the Two-Party Net Billing Agreement).

"Rating Agency" means each of Fitch IBCA, Inc., Moody's Investors Service, Inc., and Standard & Poor's Ratings Services, and their respective successors and assigns, in each case and at any time only if the same is then maintaining a rating on any Bonds at the request of the Board.

"Rating Category" means a general rating category of an applicable Rating Agency or nationally recognized statistical rating organization without regard to any refinement or gradation of such rating by a numerical modifier or otherwise.

"Record Date" with respect to each scheduled payment of principal of, premium, if any, and interest on each Bond, the date specified as the "record date" therefor in the Supplemental Resolution authorizing such Bond.

"Resolution" means the Trojan Project Revenue Bond Resolution, adopted by the Board on September 21, 2004, as the same may be amended or supplemented by a Supplemental Resolution or Resolutions.

"Revenues" means all revenues, income, rents, receipts and profits derived by the City or Board from its Ownership Share of the Trojan Project, including all payments to the Board under the Net Billing Agreements and all payments to be made by the Board pursuant to the provision described in Appendix H — "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION — Covenants — *Transfer in the Amounts of Credits Received Under the Two-Party Net Billing Agreement*" and all interest and other investment earnings on any moneys or investments held in any funds and accounts under the Resolution.

"Revenues of the Electric System" or **"Electric System Revenues"** means all income, fees, charges, receipts, profits and other moneys derived by the Board from its ownership or operation of the Electric System. (Revenues of the Electric System are referred to in the Resolution as "Revenues of the Distribution Division.")

"Series" or **"Series of Bonds"** means all of the Bonds authenticated and delivered on original issuance identified pursuant to the Supplemental Resolution authorizing such Bonds as a separate Series of Bonds and any Bonds thereafter authenticated and delivered in lieu of or in substitution therefor pursuant to the Resolution regardless of variations in maturity, interest rate or other provisions.

"Sinking Fund Installment" means, as of any particular date of calculation, the amount required, as of such date of calculation, to be paid by the Board on a future date for the retirement of Outstanding Bonds which are stated to mature subsequent to such future date, but does not include any amount payable by the Board by reason only of the maturity of a Bond.

"State" means the State of Oregon.

"Supplemental Resolution" means a resolution of the Board authorizing the issuance of a Series of Bonds or otherwise amending or supplementing the Resolution, adopted in accordance with the Resolution.

"Trojan Bond Fund" means the Trojan Revenue Bond Fund established pursuant to the Resolution.

"Trojan General Fund" means the Trojan General Fund established pursuant to the Prior Resolution and continued in effect pursuant to the Resolution.

SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION

The following is a brief summary of the Resolution. The summary does not purport to be complete or definitive and is qualified in its entirety by reference to the Resolution, a copy of which is on file in with the Bond Fund Trustee.

Resolution to Constitute Contract

In consideration of the purchase and acceptance of the Bonds by those who shall hold the same from time to time, the provisions of the Resolution shall be deemed to be and shall constitute a contract between the Board and the Holders from time to time of the Bonds. The pledge of Revenues pursuant to the Resolution, and the provisions, covenants and agreements set forth in the Resolution to be performed by or on behalf of the Board shall be for the equal benefit, protection and security of the Holders of any and all such Bonds, each of which, regardless of the time or times of its issue or maturity, shall be of equal rank without preference, priority or distinction over any other thereof except as expressly provided in the Resolution.

Obligation of Bonds

The Bonds shall be special obligations of the City payable solely from the Revenues, subject to the payment of Project Expenses, and no other revenues or assets of the Board shall be, or shall be deemed to be, pledged to the payment of the Bonds. The principal of, premium, if any, and interest on the Bonds shall not be payable from any funds of the City or the Board other than the Trojan General Fund nor shall the Bonds constitute a general obligation of the Board, or of the City, or create a charge upon the tax revenues of the City, or upon any other revenues or property of the City, or property of the Board, except the Revenues, subject to the payment of Project Expenses. Neither the faith and credit nor the taxing power of the State of Oregon or of any political subdivision thereof are pledged for the payment of the principal of, premium, if any, or interest on the Bonds, and no holder of the Bonds shall have the right to compel the exercise of the taxing power of the State of Oregon or of any political subdivision thereof in connection with any default with respect to the Bonds.

Additional Bonds

Subsequent to the issuance of the Series 2005 Bonds, the Board may issue at one time or from time to time an additional Series of the Bonds (“Additional Bonds”) for any purpose of the Board in connection with the Trojan Project, including but not limited to, any Bonds issued to refund any Bonds Outstanding, by means of a Supplemental Resolution or Supplemental Resolutions, but only upon compliance with the following conditions:

(i) An Authorized Officer shall have found and determined that no Event of Default exists.

(ii) The Board shall have determined by resolution that the Revenues will be at least sufficient to enable the Board to meet all of its obligations under the Resolution.

(iii) The Net Billing Agreements shall be for terms extending at least to the final maturity date of the Bonds, and no event of default thereunder shall exist and be continuing.

In connection with any Bonds, the Board may obtain or cause to be obtained one or more letters of credit, revolving credit agreements, surety bonds, insurance policies or similar obligations, arrangements or instruments issued by a bank, insurance company or other financial institution which provides for payment of all or a portion of the principal of and interest on any Bonds, the reimbursement obligations under which be secured by a pledge of and a lien on the Revenues, subject to the payment of Project Expenses, on a parity with the lien created thereon by the Resolution, provided, however, the Board meets the requirements for the issuance of Additional Bonds described above with respect to any such letter of credit, revolving credit agreement, surety bond, insurance policy or other agreement or arrangement. In the event any reimbursement obligations under any such letter of credit, revolving credit agreement, surety bond, insurance policy or other agreement or arrangement is secured by a pledge of and a lien on the Revenues, subject to the payment of Project Expenses, on a parity with the lien created thereon by the Resolution, such reimbursement obligations shall be treated as debt service on Bonds for all purpose of the Resolution.

Pledge Effected by the Resolution

The Bonds are payable as to principal and interest solely from and are equally and ratably secured solely by a lien on and pledge of the Revenues, subject to the payment of Project Expenses, in accordance with their terms and the provisions of the Resolution. Such pledge shall be valid and binding from the time when it is made, and the lien of such pledge shall be valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the City and the Board, irrespective of whether such parties have notice thereof. The Revenues shall immediately be subject to the lien of such pledge without any physical delivery or further act.

Continuation of Trojan General Fund and Application of Revenues

The Trojan General Fund created in the Prior Resolution shall be continued for so long as any of the Bonds are Outstanding. The City covenants and agrees that as promptly as practicable after receipt thereof by the Board, it will deposit all Revenues in the Trojan General Fund. Moneys in the Trojan General Fund shall be used and applied solely for the payment of Project Expenses and making the transfers to the Trojan Bond Fund required by the Resolution. Amounts on deposit from time to time in the Trojan General Fund shall be applied as follows and, as of any time, in the following order of priority:

> FIRST: the amount determined by the Board from time to time to pay, or to be set aside therein as a reserve for the payment of, Project Expenses shall be retained in the Trojan General Fund; and
>
> SECOND: the amounts required to pay or provide for the payment of the principal of and interest and premium, if any, on Bonds shall be transferred to the Trojan Bond Fund as described under "Trojan Revenue Bond Fund" below.

Any moneys remaining in the Trojan General Fund at any time and not deposited as set forth above shall be retained in the Trojan General Fund until no Bonds are Outstanding, or to the extent not required for the purposes set forth above, may be used to purchase Bonds. Purchases of Bonds from amounts in the Trojan General Fund shall be made at the direction of the Board, with or without advertisement and with or without notice to other Holders of Bonds. Such purchases shall be made at such price or prices as determined by the Board. If Sinking Fund Installments have been established for the maturities of Bonds purchased by the Board, then the Board shall credit the principal amount purchased against the applicable Sinking Fund Installments in such order and amounts as are determined by the Board.

Amounts in the Trojan General Fund determined to be applied to or set aside for the payment of Project Expenses shall be so applied at the times, in the manner, and on the other terms and conditions as determined by the Board from time to time.

If and to the extent provided in a Supplemental Resolution authorizing Bonds, amounts from the proceeds of such Bonds intended to pay Project Expenses shall be set aside as specified in the Supplemental Resolution providing for the issuance of such Bonds.

In the event of the refunding of any Bonds, the Board shall withdraw from the Trojan General Fund all or any portion of amounts accumulated therein with respect to the Bonds to be refunded and deposit such amounts as provided in a written direction of the Board; provided, however, that such withdrawal shall not be made unless immediately thereafter the Bonds being refunded shall be deemed to have been paid pursuant to the provision described under "Defeasance" below.

Trojan Revenue Bond Fund

There is created a special fund of the Board to be known as the "Trojan Revenue Bond Fund" (hereinafter referred to as the "Trojan Bond Fund"). The Trojan Bond Fund shall be held in trust and administered by the Bond Fund Trustee and shall be used solely for the purpose of paying the principal of, premium, if any, and interest on the Bonds and of retiring the Bonds prior to maturity in the manner provided in the Resolution. The Board shall set aside and pay (to the extent not otherwise provided) out of the moneys theretofore paid into the Trojan General Fund to the Bond Fund Trustee for deposit into the Trojan Bond Fund, amounts sufficient to pay the principal of, premium, if any, and interest on all the Bonds from time to time Outstanding as the same respectively become due and payable. Such amounts to be paid into the Trojan Bond Fund shall be as follows and in the following order of priority:

A. Not later than the last day of the month any Bonds are issued, and on or before the 25th day of each calendar month thereafter, the Board shall pay or cause to be paid into the Trojan Bond Fund to the credit of the Interest Account created therein an amount such that, if the same amount were so paid and credited to the Interest Account on the 25th day of each of the calendar months preceding the next day upon which an installment of interest falls due on the Bonds, the aggregate of the amounts so paid and credited to the Interest Account would on such date be equal to the installment of interest then falling due on all Bonds then Outstanding.

B. Not later than the 25th day of the twelfth month prior to each date upon which an installment of principal of the Bonds falls due or the last day of the month in which any Bonds are issued if an installment of principal is due less than twelve months after the date of such issuance, and on or before the 25th day of each calendar month thereafter, the Board shall pay, or cause to be paid, into the Trojan Bond Fund to the credit of the Principal Account created therein an amount such that, if the same amount were so paid and credited to the Principal Account on the 25th day of each succeeding calendar month thereafter and prior to the next date upon which an installment of principal falls due on the Bonds, the aggregate of the amounts so paid and credited to the Principal Account would on such date be equal to the installment of principal then falling due.

C. On or before the 25th day of the month which is twelve (12) months prior to the date upon which a Sinking Fund Installment is payable with respect to any Bonds of a Series of Bonds then Outstanding, and on or before the 25th day of each succeeding calendar month thereafter, the Board shall pay, or cause to be paid, into the Trojan Bond Fund to the credit of the Bond Retirement Account created therein, an amount such that, if the same amount were so set aside in the Trojan Bond Fund and credited to the Bond Retirement Account on the 25th day of each calendar month thereafter and prior to the next date upon which a Sinking Fund Installment falls due, the aggregate of the amounts so paid and credited to the Bond Retirement Account would equal the Sinking Fund Installment falling due.

Investment

Moneys held in the Trojan General Fund and the Trojan Bond Fund shall be invested and reinvested by the Board or the Bond Fund Trustee at the direction of the Board, respectively, to the fullest extent practicable in Investment Securities which mature not later than at such times as shall be necessary to provide moneys when needed for payments to be made from such Fund. In making any investment in any Investment Securities with moneys in any Fund continued or established under the Resolution, the Board may combine such moneys with moneys in any other Fund continued or established under the Resolution, but solely for purposes of making such investment in such Investment Securities. Interest (net of that which represents a return of accrued interest paid in connection with the purchase of any investment) and other investment earnings on any moneys or investments shall be paid into the Trojan General Fund as and when received.

Covenants

Transfer in the Amounts of Credits Received Under the Two-Party Net Billing Agreement. If and to the extent the Board receives a net billing credit pursuant to the Two-Party Net Billing Agreement, the Board shall transfer from the Electric System Revenue Fund to the Trojan General Fund an amount equal to the amount of the credit received. The obligation to make such transfer shall be an Operating Expense of the Electric System. An amount equal to a credit so received shall be so transferred to the Trojan General Fund no later than the date payment of such amount would have been due to Bonneville if a net billing credit had not been received.

Annual Budget. Not less than ten days prior to the beginning of each calendar year, the Board shall prepare an Annual Budget for the ensuing calendar year. The Annual Budget shall set forth in reasonable detail the estimated Revenues and Project Expenses for such year and shall include an estimate of all other expenditures by the Board in connection with the Trojan Project for such year. The Annual Budget shall provide for all Project costs. From time to time during each calendar year the Board shall review its estimates of Revenues and Project Expenses for such calendar year, and if there are at any time during any such calendar year extraordinary receipts or payments of unusual costs for the Trojan Project, the Board may prepare an amended Annual Budget.

Continuation of Electric System Revenue Fund; Electric System Revenues; No Superior Claims. The Electric System Revenue Fund is continued for the purposes of the Resolution and the Electric System Resolution. All Electric System Revenues shall be deposited in the Electric System Revenue Fund. The Board covenants and agrees that it will not incur any debt, claim or other obligation or issue any bonds, notes or other evidences of indebtedness payable from the Electric System Revenues which will rank in priority over the payments required by the Resolution to be made into the Trojan General Fund.

Rate Covenants. The Board shall fix, establish and collect, or cause to be fixed, established and collected, rates, tolls, rents and other charges for electric power and energy (including capability) and for any services or facilities sold, furnished or supplied by the Electric System or any part thereof, which rates, tolls, rents and charges shall be sufficient to meet the Board's obligation described under the " - *Transfer in the Amounts of Credits Received Under the Two-Party Net Billing Agreement*" and all other charges against the Electric System Revenue Fund.

The Board shall fix, establish and collect, or cause to be fixed, establish or collected, rates, tolls, rents and other charges for electric power and energy (including capability) and for any services or facilities sold, furnished or supplied by the City's Ownership Share of the Trojan Project sufficient to pay all Project Expenses and the principal of and premium, if any, and interest on the Bonds as they become due and all other charges against the Revenues.

Payment of Debt Service. The Board shall pay principal of and premium, if any, and, interest on all Outstanding Bonds as the same shall become due and payable.

Amendment of Trojan Ownership Agreement and Net Billing Agreements. So long as any Bonds are Outstanding, the Board will not voluntarily consent to or permit any rescission of, nor will it consent to any amendment to nor otherwise take any action under or in connection with, the Trojan Ownership Agreement or any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of the Board or of the Holders from time to time of the Bonds, and the Board shall perform all of its obligations under, and take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Bonds afforded by, the provisions of such agreements.

Accounts and Reports. 1. The Board shall keep proper books of record and account (separate from all other records and accounts) in which complete and correct entries shall be made of its transactions relating to the Trojan Project, the Trojan General Fund and Trojan Bond Fund and which shall at all times be subject to the inspection of the Bond Fund Trustee and the Holders of an aggregate of not less than 5% in principal amount of the Bonds then Outstanding or their representatives duly authorized in writing.

2. The Bond Fund Trustee shall advise the Board promptly after the end of each month of its transactions during such month relating to the Trojan Bond Fund.

3. The Board shall from time to time appoint a certified public accountant, or firm of certified public accountants, of favorable repute, as the Accountant, and shall cause such accounts to be audited by the Accountant. Written evidence of the appointment of each Accountant shall be filed by the Board with the Bond Fund Trustee. The Board shall annually, within 120 days after the close of each calendar year (the first such report to be filed with respect to the year 2005), file with the Bond Fund Trustee, and otherwise as provided by law, a copy of an audit report for such year.

4. The reports, statements and other documents required to be furnished to the Bond Fund Trustee pursuant to any provisions of the Resolution shall be available for the inspection of Bondholders at the office of the Bond Fund Trustee, and shall be mailed to each Bondholder who shall file a written request therefor with the Board.

5. The Board shall file with the Bond Fund Trustee forthwith upon becoming aware of any Event of Default or default in the performance by the Board of any covenant, agreement or condition contained in the Resolution, a certificate signed by the President and Treasurer of the Board specifying such Event of Default or default.

Authority to Issue Bonds and Pledge Revenues and Other Funds. The City is duly authorized under all applicable laws to create and issue the Bonds and to adopt the Resolution and to pledge the Revenues, subject to the payment of Project Expenses, in the manner and to the extent provided in the Resolution. The Revenues are and will be free and clear of any pledge, lien, charge or encumbrance thereon or with respect thereto prior to, or of equal rank with, the pledge created by the Resolution, but are subject to the payment of Project Expenses, and all action on the part of the Board to that end has been duly and validly taken. The Bonds and the provisions of the Resolution are and will be the valid and legally enforceable obligations of the City in accordance with their terms and the terms of the Resolution. The Board shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the Revenues, subject to the payment of Project Expenses, pledged under the Resolution and all the rights of the Bondholders under the Resolution against all claims and demands of all persons whomsoever.

Further Assurances. The Board will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights and Revenues pledged or assigned to the payment of the Bonds, subject to the payment of Project Expenses, or intended so to be, or which the Board may hereafter become bound to pledge or assign.

Covenants in the Electric System Resolution. So long as any Bonds are Outstanding, the Board will comply with the covenants contained in the Electric System Resolution.

Tax Covenant. The Board shall not take or omit to take any action which would cause interest on any Series 2005 Bond to be included in the gross income of any Owner thereof for Federal income tax purposes by reason of subsection (b) of Section 103 of the Code. Without limiting the generality of the foregoing, no part of the proceeds of any Bonds or any other Revenues shall be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Series 2005A Bond to be an "arbitrage bond" as defined in section 148 of the Code and to be subject to treatment under subsection (b)(2) of Section 103 of the Code as an obligation not described in subsection (a) of said section.

Supplemental Resolutions

For any one or more of the following purposes and at any time or from time to time, a Supplemental Resolution may be adopted by the Board which, upon the filing with the Bond Fund Trustee of a copy thereof certified by an Authorized Representative (without the consent of any Holder), shall be fully effective in accordance with its terms: to close the Resolution against, or provide limitations and restrictions in addition to the limitations and restrictions contained in the Resolution on, the issuance of Bonds or other evidences of indebtedness; to add to the covenants and agreements of the Board in the Resolution other covenants and agreements to be observed by the Board which are not contrary to or inconsistent with the Resolution as theretofore in effect; to add to the limitations and restrictions in the Resolution other limitations and restrictions to be observed by the Board; to surrender any right, power or privilege reserved to or conferred upon the Board by the terms of the Resolution, but only if the surrender of such right, power or privilege is not contrary to or inconsistent with the covenants and agreements of the Board contained in the Resolution; to authorize Bonds and, in connection therewith, specify and determine matters and things relative to such Bonds which are not contrary to or inconsistent with the Resolution as theretofore in effect, or to amend, modify or rescind any such authorization, specification or determination at any time prior to the first authentication and delivery of such Bonds; to confirm, as further assurance, any pledge under, and the subjection of any other property to any lien or pledge created or to be created by, the Resolution; to modify any of the provisions of the Resolution to permit compliance with any amendment to the Internal Revenue Code of 1986, as amended, or any successor thereto, as the same may be in effect from time to time, if, in the Opinion of Bond Counsel, failure to so modify the Resolution either would adversely affect the ability of the Board to issue Bonds the interest on which is excludable from gross income for purposes of federal income taxation, or is necessary or advisable to preserve such exclusion with respect to any Outstanding Bonds; to modify, amend or supplement the Resolution in such manner as to permit the qualification thereof under the Trust Indenture Act of 1939, as amended, or any similar Federal statute hereafter in effect or to permit the qualification of the Bonds for sale under the securities laws of any of the states of the United States of America, and, if the Board so determines, to add thereto such other terms, conditions and provisions as may be permitted by said Trust Indenture Act of 1939 or similar Federal statute; to comply with such regulations and procedures as are from time to time in effect relating to establishing and maintaining a book-entry-only system; to provide for the issuance of Bonds in coupon form payable to bearer; to comply with the requirements of any Rating Agency in order to maintain or improve a rating on the Bonds by such Rating Agency; to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in the Resolution; to insert such provisions clarifying matters or questions arising under the Resolution as are necessary or desirable and are not contrary to or inconsistent with the Resolution as theretofore in effect; to modify any provision thereof or of any previously adopted Supplemental Resolution in any respect, provided that such modification shall not adversely affect the interests of the Bondholders in any material respect; to modify any of the provisions of the Resolution in any respect whatsoever, provided that (a) such modification is to be effective upon or prior to the issuance of any Bonds affected thereby, or (b) such modification shall be, and be expressed to be, effective only after all Bonds Outstanding at the date of the adoption of such Supplemental Resolution shall cease to be Outstanding; or with the consent of the Bond Fund Trustee, to modify any provision of the Resolution or of any previously adopted Supplemental Resolution in any respect, provided that such amendment shall not adversely affect the interests of the Bondholders in any material respect.

Amendments

Any modification or amendment of the Resolution or of the rights and obligations of the Board and of the Holders of the Bonds, in any particular, may be made by a Supplemental Resolution, with the written consent (i) of the Holders of at least a majority in principal amount of the Bonds Outstanding at the time such consent is given and (ii) in case less than all Bonds then Outstanding are affected by the modification or amendment, of the Holders of at least a majority in principal amount of such Outstanding Bonds that are or may be so affected; except that if such modification or amendment will, by its terms, not take effect so long as any particular Bonds remain Outstanding, the consent of the Holders of such Bonds shall not be required and such Bonds shall not be deemed to be Outstanding for the purpose of any calculation of Outstanding Bonds related to such amendment. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any Outstanding Bond or of any installment of interest thereon or a reduction in the principal amount thereof or premium thereon or in the rate of interest thereon without the consent of the Holder of such Bond, or shall reduce the percentages or otherwise affect the classes of Bonds the consent of the Holders of which is required to effect any such modification or amendment, or shall change or modify any of the rights or obligations of the Bond Fund Trustee without its written assent thereto. For purposes related to such amendment, a Bond shall be deemed to be affected by a modification or amendment of the Resolution if the same materially and adversely affects or diminishes the rights of the Holder of such Bond. The Bond Fund Trustee may in its reasonable discretion determine whether, in accordance with the foregoing powers of amendment, particular Bonds would be affected by any modification or amendment hereof and any such determination shall be binding and conclusive on the Board and all Holders of Bonds.

Events of Default

Each of the following events is defined as and shall constitute an "Event of Default":

(1) a default in the due and punctual payment of the principal of or the premium, if any, on any Bond when and as the same shall become due and payable, whether at maturity or upon call for redemption, or otherwise; or

(2) a default in the due and punctual payment of any installment of interest on any Bond, when and as such interest installment shall become due and payable; or

(3) default by the Board in the performance or observance of any other of the covenants, agreements or conditions on its part contained in the Resolution, any Supplemental Resolution or in the Bonds, and such default shall continue for a period of sixty (60) days after written notice thereof stating that such notice is a "Notice of Default" is delivered to the Board by the Bond Fund Trustee or to the Board and the Bond Fund Trustee by the Holders of not less than sixty-six and two-thirds percent (66-2/3%) of the principal amount of the Bonds Outstanding, provided that if such default shall be such that it cannot be corrected within such sixty day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected; or

(4) if the Board (1) files a petition seeking a composition of its indebtedness under the Federal bankruptcy laws, or under any other applicable law or statute of the United States of America or of the State; (2) consents to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or other similar official of the Board or any substantial portion of its property; (3) makes any assignment for the benefit of creditors; or (4) admits in writing its inability generally to pay its debts generally as they become due; or

(5) if (a) a decree or order for relief is entered by a court having jurisdiction of the City or the Board adjudging it a bankrupt or insolvent or approving as properly filed a petition seeking

reorganization, arrangement, adjustment or composition in respect of the City or the Board in an involuntary case under the Federal bankruptcy laws, or under any other applicable law or statute of the United States of America or of the State; (b) a receiver, liquidator, assignee, custodian, trustee, sequestrator or other similar official of the City or the Board or of any substantial portion of its property is appointed; or (c) the winding up or liquidation of its affairs is ordered and the continuance of any such decree or orders is unstayed and in effect for a period of sixty (60) consecutive days.

Remedies

Acceleration. Upon the happening and continuance of any Event of Default, the Bond Fund Trustee may and, upon the written request of the Holders of not less than sixty-six and two-thirds percent (66-2/3%) of the principal amount of the Bonds Outstanding shall, in any such case, unless the principal of all the Bonds then Outstanding shall already have become due and payable, declare the principal of all the Bonds then Outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable, anything in the Resolution or in any of the Bonds contained to the contrary notwithstanding. The right of the Bond Fund Trustee to make any such declaration as aforesaid, however, is subject to the condition that if, at any time after such declaration, but before the Bonds shall have matured by their terms, all overdue installments of principal and interest upon the Bonds, together with the reasonable and proper charges, expenses and liabilities of the Bond Fund Trustee, and all other sums then payable by the Board under the Resolution (except the interest accrued since the next preceding interest date on the Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of the Board or provision satisfactory to the Bond Fund Trustee shall be made for such payment, and all defaults under the Bonds or under the Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall be made good or be secured to the satisfaction of the Bond Fund Trustee or provision deemed by the Bond Fund Trustee to be adequate shall be made therefor, then and in every such case the Holders of a majority in principal amount of the Bonds Outstanding, by written notice to the Board and to the Bond Fund Trustee, may rescind such declaration and annul such default in its entirety, or, if the Bond Fund Trustee shall have acted without a direction from the Holders of the Bonds as aforesaid at the time of such request, and if there shall not have been theretofore delivered to the Bond Fund Trustee written direction to the contrary by the Holders of sixty-six and two-thirds percent (66-2/3%) of the principal amount of the Bonds then Outstanding, then any such declaration shall ipso facto be deemed to be rescinded and any such default and its consequences shall ipso facto be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any right or power consequent thereon.

Application of Revenues and Other Moneys After Default. The Board covenants that, if an Event of Default shall happen and shall not have been remedied, the Board, upon demand of the Bond Fund Trustee, shall pay over or cause to be paid over to the Bond Fund Trustee (i) forthwith, any moneys, securities and funds then held by the Board in any Fund under the Resolution, and (ii) as promptly as practicable after receipt thereof, the Revenues. During the continuance of an Event of Default, the Bond Fund Trustee shall apply such Revenues and the income therefrom as follows and in the following order.

(1) To the payment of the reasonable and proper charges and expenses of the Bond Fund Trustee.

(2) To the payment of the amounts required for reasonable and necessary Project Expenses.

(3) To the payment of the interest and principal or redemption price then due on the Bonds as follows:

(i) unless the principal thereof shall have become or have been declared due and payable, FIRST: to the payment to the persons entitled thereto of all installments of interest then due and payable in the order of the maturity of such installments and, if the amount available shall not be sufficient to pay in full any installment or installments maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

SECOND: to the payment to the persons entitled thereto of the unpaid principal or redemption price, or principal and redemption premium, if any, of any Bonds which shall have become due and payable, whether at maturity or by call for redemption (other than Bonds called for redemption for the payment of which moneys are held pursuant to the Resolution), in the order of their due dates, with interest thereon at the rate or rates, if any, expressed therein from the respective dates upon which they become due and, if the amount available shall not be sufficient to pay in full all Bonds due on any particular date, together with such interest, if any, then to the payment thereof ratably, according to the amounts of principal or redemption price, or principal and redemption premium, if any, due on such date, to the persons entitled thereto, without any discrimination or preference.

(ii) if the principal of all of the Bonds shall have become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon the Bonds without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any Bond over any other Bond, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Proceedings Brought by Bond Fund Trustee. If an Event of Default shall happen and shall not have been remedied, then and in every such case, the Bond Fund Trustee, by its agents and attorneys, if the Bond Fund Trustee shall deem it advisable, may proceed to protect and enforce its rights and the rights of the Holders of the Bonds under the Resolution forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant contained in the Resolution, or in aid of the execution of any power granted in the Resolution, or for an accounting against the Board as if the Board were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Bond Fund Trustee, being advised by counsel, shall deem most effectual to enforce any of its rights or to perform any of its duties under the Resolution.

The Holders of not less than sixty-six and two-thirds percent (66-2/3%) in principal amount of the Bonds at the time Outstanding may direct by instrument in writing the time, method and place of conducting any proceeding for any remedy available to the Bond Fund Trustee, or exercising any trust or power conferred upon the Bond Fund Trustee, provided that the Bond Fund Trustee shall have the right to decline to follow any such direction if the Bond Fund Trustee shall be advised by counsel that the action or proceeding so directed may not lawfully be taken, or if the Bond Fund Trustee in good faith shall determine that the action or proceeding so directed would involve the Bond Fund Trustee in personal liability or be unjustly prejudicial to the Bondholders not parties to such direction.

Upon commencing a suit in equity or upon other commencement of judicial proceedings by the Bond Fund Trustee to enforce any right under the Resolution, the Bond Fund Trustee shall be entitled to exercise any and all rights and powers conferred in the Resolution and provided to be exercised by the Bond Fund Trustee upon the occurrence of an Event of Default; and, as a matter of right against the Board, without notice or demand and without regard to the adequacy of the security for the Bonds, the Bond Fund Trustee shall, to the extent permitted by law, be entitled to the appointment of a receiver of the moneys, securities and funds then held by the Board in any Fund or Account under the Resolution and, with all such powers as the court or courts making such appointment shall confer; but, notwithstanding the appointment of any receiver, the Bond Fund Trustee shall be entitled to retain possession and control of and to collect and receive income from, any moneys, securities and funds deposited or pledged with it under the Resolution or agreed or provided to be delivered or pledged with it under the Resolution.

Regardless of the happening of an Event of Default, the Bond Fund Trustee shall have the power to, but (unless requested in writing by the Holders of not less than sixty-six and two-thirds percent (66-2/3%) in principal amount of the Bonds then Outstanding and furnished with reasonable security and indemnity) shall be under no obligation to, institute and maintain such suits and proceedings as it may be advised shall be necessary or expedient to prevent any impairment of the security under the Resolution by any acts which may be unlawful or in violation of the Resolution, and such suits and proceedings as the Bond Fund Trustee may be advised shall be necessary or expedient to preserve or protect its interests and the interests of the Bondholders.

Restriction on Bondholders' Action. No Holder of any Bond shall have any right to institute any suit, action or proceeding at law or in equity for the enforcement of any provision of the Resolution or the execution of any trust under the Resolution or for any remedy under the Resolution, unless such Holder shall have previously given to the Bond Fund Trustee written notice of the happening of an Event of Default, and the Holders of not less than sixty-six and two-thirds percent (66-2/3%) in principal amount of the Bonds then Outstanding shall have filed a written request with the Bond Fund Trustee, and shall have offered it reasonable opportunity, either to exercise the powers granted or to institute such action, suit or proceeding in its own name, and unless such Holders shall have offered to the Bond Fund Trustee adequate security and indemnity against the costs, expenses and liabilities to be incurred therein or thereby, and the Bond Fund Trustee shall have refused to comply with such request within a reasonable time; it being understood and intended that no one or more Holders of Bonds shall have any right in any manner whatever by his or their action to affect, disturb or prejudice the pledge created by the Resolution, or to enforce any right under the Resolution, except in the manner therein provided; and that all proceedings at law or in equity to enforce any provision of the Resolution shall be instituted, had and maintained in the manner provided in the Resolution and for the equal benefit of all Holders of the Outstanding Bonds.

Defeasance

Any Outstanding Bonds or any portion thereof shall prior to the maturity or redemption date thereof be deemed to have been paid if (i) in case any of said Bonds are to be redeemed on any date prior to their maturity, the Board shall have given to the Bond Fund Trustee instructions accepted in writing by the Bond Fund Trustee to mail notice of redemption of such Bonds (other than Bonds which have been purchased by the Board as hereinafter provided prior to the mailing of such notice of redemption) on said date, (ii) there shall have been deposited with the Bond Fund Trustee either moneys in an amount which shall be sufficient, or Defeasance Obligations the principal installments of and/or the interest on which when due, without reinvestment, will provide moneys which, together with the moneys, if any, deposited with the Bond Fund Trustee at the same time, shall be sufficient, to pay when due the principal of or premium, if any, and interest due and to become due on said Bonds or portion thereof on or prior to the redemption date or maturity date thereof, as the case may be, and (iii) in the event said Bonds are not to be redeemed within the next succeeding 60 days, the Board shall have given the Bond Fund Trustee in form satisfactory to it irrevocable instructions to mail, as soon as practicable, a notice to the Holders of such Bonds that the deposit required by clause (ii) above has been made with the Bond Fund Trustee and that said Bonds or portion thereof (as the same thereafter may change) are deemed to have been paid in accordance with this provision and stating such maturity or redemption date (as the same thereafter may change) upon which moneys are to be available for the payment of the principal or premium, if any, on said Bonds or portion thereof (other than Bonds which have been purchased by the Board as hereinafter provided prior to the publication of the notice of redemption referred to in clause (i) hereof). The Bond Fund Trustee also shall mail, as soon as practicable, a notice to the Holders of any Bonds affected by any change contemplated by the preceding clause (iii), describing such change.

The term "Defeasance Obligations" shall mean (i) direct general obligations of, or obligations the payment of the principal and interest of which are unconditionally guaranteed by, the United States of

America which are non-callable or redeemable only at the option of the holder and which at the time are legal investments for the moneys proposed to be invested therein, (ii) receipts, certificates or other similar documents evidencing ownership of future interest or principal payments due on direct obligations of the United States of America held in a custody or trust account by a commercial bank (having at least $20,000,000 in capital stock, surplus and undivided profits) pursuant to a custody or trust agreement, (iii)(A) direct and general obligations, to the payment of the principal of and interest on which the full faith and credit of the issuer is pledged, of any of the following: any state of the United States, or any political subdivision of any such state; provided that (1) as to such obligations of a political subdivision, all the taxable real property within such political subdivision shall be subject to taxation thereby to pay such obligations and the interest thereon, without limitation as to rate or amount, and (2) at the time of their purchase under this Resolution, such obligations of any such state or political subdivision are rated in either of the two highest rating categories by two nationally recognized bond rating agencies, or (B) long-term obligations of any state or any political subdivision thereof the entire principal of and interest on which is insured pursuant to an irrevocable municipal bond insurance policy and which obligations are rated by two nationally recognized bond rating agencies in the highest rating category or (iv) noncallable obligations of any state or any political subdivision thereof, the District of Columbia or any possession of the United States which obligations are rated in the highest rating category by Moody's Investors Service and Standard & Poor's Ratings Services and provision for the payment of the principal of and interest on which shall have been made by deposit with a trustee or escrow agent of direct obligations of the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or possession thereof or any state or the District of Columbia in the capacity as custodian, the maturing principal of and interest on which obligations when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession, or political subdivision.

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APPENDIX I

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENT

To assist the Underwriters in complying with Rule 15c2-12, the Board and Bonneville will enter into a written agreement (the "Agreement") for the benefit of the holders and beneficial owners of the Series 2005 Bonds to provide continuing disclosure.

Definitions

In addition to the definitions set forth elsewhere in this Official Statement, which apply to any capitalized term used in the Agreement, the following capitalized terms shall have the following meanings:

"Board Annual Information" means financial information and operating data generally of the type included in Appendix C of the Official Statement for the Series 2005 Bonds under the captions "Customer Sales and Revenues", "Largest Customers" and "Historical Electric System Operating Results".

"Board Fiscal Year" means the fiscal year ending each December 31 or, if such fiscal year end is changed, on such new date; provided that if the Board Fiscal Year is changed, the Board shall notify, in a timely manner, each NRMSIR and the SID, if any.

"BPA Annual Information" means financial information and operating data generally of the type included in the following tables in Appendix A of the Official Statement for the Series 2005 Bonds under the headings "BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Historical Federal System Financial Data — Federal System Statement of Revenues and Expenses," "— Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" and "— Statement of Net Billing Obligations and Expenditures."

"FCRPS" means the Federal Columbia River Power System.

"FCRPS Fiscal Year" means the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year is changed, Bonneville shall notify, in a timely manner, each NRMSIR and the SID, if any.

"MSRB" means the Municipal Securities Rulemaking Board or any successor to its functions.

"NRMSIR" means a nationally recognized municipal securities information repository.

"Rule l5c2-12" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of the Agreement, including any official interpretations thereof promulgated on or prior to the effective date of the Agreement.

"SID" means a state information depository for the State of Oregon, if any.

Financial Information

Bonneville. Bonneville agrees to provide to each NRMSIR and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2005:

(i) the BPA Annual Information for the FCRPS Fiscal Year; and

(ii) annual financial statements of the FCRPS for the FCRPS Fiscal Year prepared in accordance with generally accepted accounting principles; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville shall notify the Board when such BPA Annual Information has been provided and when such financial statements have been provided.

The Board. The Board agrees to provide to each NRMSIR and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each Board Fiscal Year, commencing with Board Fiscal Year ending December 31, 2005:

(i) the Board Annual Information for the Board Fiscal Year, and

(ii) annual financial statements of the Board for the Board Fiscal Year prepared in accordance with generally accepted accounting principles applicable to governmental entities; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not its audited annual financial statements, the Board shall provide its audited annual financial statements when and if they become available.

Cross-Reference. In lieu of providing the annual financial information and operating data described above, Bonneville and the Board may cross-refer to other documents provided to the NRMSIR, the SID, if any, or to the SEC and, if such document is a final official statement within the meaning of the Rule, available from the MSRB.

Notice of Failure to Provide Financial Information. The Board agrees to provide or cause to be provided, in a timely manner, to each NRMSIR or to the MSRB and to the SID, if any, notice of its or Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above.

Material Events Notices

The Board agrees to provide or cause to be provided, in a timely manner, to the SID, if any, and to each NRMSIR or to the MSRB, notice of the occurrence of any of the following events with respect to the Series 2005 Bonds, if material:

(i) principal and interest payment delinquencies;

(ii) Non-payment related defaults;

(iii) Unscheduled draws on debt service reserves reflecting financial difficulties;

(iv) Unscheduled draws on credit enhancements reflecting financial difficulties;

(v) Substitution of credit or liquidity providers, or their failure to perform;

(vi) Adverse tax opinions or events affecting the tax-exempt status of the 2005 Bonds;

(vii) Modifications to rights of Series 2005 Bond holders;

(viii) Optional, contingent or unscheduled calls of any Series 2005 Bonds;

(ix) Defeasances;

(x) Release, substitution or sale of property securing repayment of the 2005 Bonds; and

(xi) Rating changes.

Solely for purposes of disclosure, and not intending to modify this undertaking, the Board advises with reference to items (iii), (iv) and (x) above that no credit enhancements, debt service reserves or property secure payment of the Series 2005 Bonds, and with respect to item (viii) above, that the Series 2005 Bonds are not subject to redemption prior to maturity.

Termination, Modification

The obligations of Bonneville and the Board to provide annual financial information and the obligation of the Board to provide notices of material events shall terminate upon the legal defeasance or payment in full of all of the Series 2005 Bonds. Bonneville and the Board may amend the Agreement, and any provision of the Agreement may be waived, with an approving opinion of nationally recognized bond counsel and in accordance with the Rule.

In the event of any amendment or waiver of a provision of the Agreement, Bonneville and the Board shall describe such amendment in the next annual report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville or the Board, as applicable. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the same manner as for a material event, and (ii) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Remedies

The right of any Owner or Beneficial Owner of Series 2005 Bonds to enforce the provisions of the Agreement against the Board shall be limited to a right to obtain specific enforcement of the Board's obligations thereunder, and any failure by the Board to comply with the provisions of the Agreement shall not be an event of default under the Resolution or with respect to the Series 2005 Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under the Agreement. Owners and Beneficial Owners of Series 2005 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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APPENDIX J

THE DEPOSITORY TRUST COMPANY

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation and Emerging Markets Clearing Corporation (NSCC, FICC, and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission.

Purchases of Series 2005 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2005 Bonds on DTC's records. The ownership interest of each actual purchaser of each Security ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Series 2005 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Series 2005 Bonds, except in the event that use of the book-entry system for the Series 2005 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2005 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Series 2005 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2005 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2005 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Series 2005 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Series 2005 Bonds, such as defaults, and proposed amendments to the security documents. For example, Beneficial Owners of Series 2005 Bonds may wish to ascertain that the nominee holding the Series 2005 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to Series 2005 Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Board as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Series 2005 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the Series 2005 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Board or Agent, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, Agent, or the Board, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Board or Agent, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as depository with respect to the Series 2005 Bonds at any time by giving reasonable notice to the Board or Agent. Under such circumstances, in the event that a successor depository is not obtained, Security certificates are required to be printed and delivered.

The Board may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository). In that event, Security certificates will be printed and delivered to DTC.

The information in this section concerning DTC and DTC's book-entry system has been obtained from DTC. The Board makes no representation as to the completeness or the accuracy of such information or as to the absence of material adverse changes in such information subsequent to the date hereof.

THE BOARD WILL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO PARTICIPANTS, TO INDIRECT PARTICIPANTS, OR TO ANY BENEFICIAL OWNER WITH RESPECT TO (I) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC, ANY PARTICIPANT, OR ANY INDIRECT PARTICIPANT; (II) THE PAYMENT BY DTC OR ANY PARTICIPANT OR INDIRECT PARTICIPANT OF ANY AMOUNT WITH RESPECT TO THE PRINCIPAL OF OR INTEREST ON THE SERIES 2005 BONDS; (III) ANY NOTICE THAT IS PERMITTED OR REQUIRED TO BE GIVEN TO BONDHOLDERS; OR (IV) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS BOND OWNER.

CITY OF EUGENE, OREGON • TROJAN PROJECT REVENUE BONDS • REFUNDING SERIES 2005

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