NEW ISSUE—Full Book-Entry Ratings: See "RATINGS" herein.

*In the opinion of Bond Counsel, interest on the 2003 Bonds will be excluded from gross income subject to federal income taxation pursuant to the Internal Revenue Code of 1986, as amended, subject to certain conditions and assumptions described herein under "TAX EXEMPTION." The 2003 Bonds are not private activity bonds. Interest on the 2003 Bonds is included in the computation of certain federal taxes on corporations.*

# PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY, WASHINGTON
# Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003
# $146,210,000

**Dated: Date of Delivery** **Due: October 1, as shown below**

Public Utility District No. 1 of Lewis County, Washington (the "District") will issue its Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 (the "2003 Bonds") as fully registered bonds under a book-entry-only system, initially registered in the name of Cede & Co. (the "Registered Owner"), as nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2003 Bonds. Individual purchases of the 2003 Bonds will be made in the principal amount of $5,000 or any integral multiple thereof within a single maturity. Purchasers of the 2003 Bonds (the "Beneficial Owners") will not receive certificates representing their interest in the 2003 Bonds. Principal and interest are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Registrar").

Principal is payable as set forth below. Interest on the 2003 Bonds is payable on October 1, 2003, and semiannually thereafter on each April 1 and October 1 to maturity or earlier redemption, by the Bond Registrar to DTC, which in turn is obligated to remit principal and interest to its broker-dealer participants for subsequent disbursement to Beneficial Owners of the 2003 Bonds. See APPENDIX D — "BOOK-ENTRY SYSTEM."

The 2003 Bonds are subject to redemption prior to their stated maturities. See "DESCRIPTION OF THE 2003 BONDS — Redemption."

**MATURITIES, AMOUNTS, INTEREST RATES AND YIELDS**

| Year (October 1) | Amount | Interest Rate | Yield | CUSIP No. | Year (October 1) | Amount | Interest Rate | Yield | CUSIP No. |
|---|---|---|---|---|---|---|---|---|---|
| 2005 | $ 3,700,000 | 5.00% | 1.65% | 527839BR4 | 2015 | $ 7,190,000† | 5.00% | 3.67◆% | 527839CB8 |
| 2006 | 4,700,000 | 5.00 | 1.86 | 527839BS2 | 2016 | 7,545,000† | 5.00 | 3.82◆ | 527839CC6 |
| 2007 | 1,880,000 | 5.00 | 2.19 | 527839BT0 | 2017 | 7,930,000† | 5.00 | 3.92◆ | 527839CD4 |
| 2007 | 3,050,000* | 2.75 | 2.09 | 527839CM4 | 2018 | 8,325,000† | 5.00 | 4.04◆ | 527839CE2 |
| 2008 | 5,110,000* | 5.00 | 2.40 | 527839BU7 | 2019 | 8,740,000† | 5.00 | 4.14◆ | 527839CF9 |
| 2009 | 5,360,000* | 5.00 | 2.66 | 527839BV5 | 2020 | 9,175,000† | 5.00 | 4.23◆ | 527839CG7 |
| 2010 | 5,630,000* | 5.00 | 2.97 | 527839BW3 | 2021 | 9,635,000† | 5.00 | 4.30◆ | 527839CH5 |
| 2011 | 5,915,000* | 5.00 | 3.18 | 527839BX1 | 2022 | 10,120,000† | 5.00 | 4.37◆ | 527839CJ1 |
| 2012 | 6,215,000* | 5.00 | 3.32 | 527839BY9 | 2023 | 11,035,000† | 5.00 | 4.42◆ | 527839CK8 |
| 2013 | 6,520,000† | 5.00 | 3.35 | 527839BZ6 | 2024 | 11,585,000† | 4.625 | 4.55◆ | 527839CL6 |
| 2014 | 6,850,000† | 5.00 | 3.49◆ | 527839CA0 | | | | | |

* Insured by XL Capital Assurance Inc.
† Insured by MBIA Insurance Corporation
◆ Priced to the par call date of October 1, 2013

The 2003 Bonds are being issued to refund the Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991 (the "1991 Bonds") issued for the purpose of financing the construction of the Cowlitz Falls Hydroelectric Project (the "Project" or "Cowlitz Falls Project"), a hydroelectric facility located on the Cowlitz River in Lewis County, Washington, to refund the Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 1993 (the "1993 Bonds") issued for the purpose of refunding a portion of the 1991 Bonds, and to pay costs of issuance of the 2003 Bonds. See "PURPOSE OF THE 2003 BONDS AND APPLICATION OF THE 2003 BOND PROCEEDS."

The United States of America, Department of Energy, acting by and through the Administrator of the

# BONNEVILLE POWER ADMINISTRATION

("Bonneville"), has entered into a Power Purchase Contract with the District and a Payment Agreement with the Trustee. Pursuant to the Power Purchase Contract, all of the output of the Project through June 30, 2032 has been sold to Bonneville and Bonneville is obligated to pay all Project Power Costs (as defined in the Power Purchase Contract), including debt service on the 2003 Bonds, whether or not the Project is terminated, operating or operable. Bonneville is further obligated pursuant to the Payment Agreement to pay debt service on the 2003 Bonds if it does not make such payments under the Power Purchase Contract. See APPENDIX E — "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT." Bonneville's payments under the Power Purchase Contract and the Payment Agreement may be made solely from the Bonneville Fund as described herein. Such obligations are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.

Payment of the principal of and interest on $3,050,000 of the 2003 Bonds maturing in 2007 and the 2003 Bonds maturing in 2008 through 2012 will be insured by a municipal bond insurance policy to be issued by XL Capital Assurance Inc. simultaneously with the delivery of the 2003 Bonds.

Payment of the principal of and interest on the 2003 Bonds maturing in 2013 through 2024 will be insured by a municipal bond insurance policy to be issued by MBIA Insurance Corporation simultaneously with the delivery of the 2003 Bonds.

**The 2003 Bonds are special limited obligations of the District payable from the revenues derived from the Cowlitz Falls Project, and are not obligations of the State of Washington or of any political subdivision thereof, other than the District. The 2003 Bonds do not constitute a general obligation of the District or a charge upon any general fund or upon any money or property of the District, including the District's Electric System, except the Cowlitz Falls Revenues, as described herein, and money in certain funds and accounts held under the Bond Resolution.**

This cover page is not intended to be a summary of the terms of, or security for, the 2003 Bonds. Investors are advised to read the entire Official Statement to obtain information essential to making an informed investment decision.

*The 2003 Bonds are offered for delivery when, as and if issued and received by the Underwriters, subject to prior sale, to withdrawal or modification of the offer without notice, and to the approval of legality by Preston Gates & Ellis LLP, Bond Counsel, Seattle, Washington. Certain legal matters will be passed upon for the Underwriters by their counsel, Foster Pepper & Shefelman, PLLC and for Bonneville by its General Counsel and its Special Counsel, Orrick, Herrington & Sutcliffe LLP. It is expected that the 2003 Bonds will be delivered on or about July 16, 2003 at the facilities of DTC in New York, New York, or to the Bond Registrar on behalf of DTC by Fast Automated Securities Transfer.*

**CITIGROUP** **SEATTLE-NORTHWEST SECURITIES CORPORATION**

Dated: June 19, 2003

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**PUBLIC UTILITY DISTRICT NO. 1**
**OF LEWIS COUNTY, WASHINGTON**
**321 Northwest Pacific Avenue**
**Chehalis, Washington 98532**

**BOARD OF COMMISSIONERS**

| | |
|---|---|
| Charles R. TenPas | President |
| James H. Hubenthal | Vice President |
| John L. Kostick | Secretary |

**MANAGEMENT**

| | |
|---|---|
| David J. Muller | Manager |
| Rich Bauer | Treasurer/Controller |
| James R. Haselwood | Auditor |
| Ronald D. Raff | Superintendent |

**BOND COUNSEL**

Preston Gates & Ellis LLP
Seattle, Washington

**BONNEVILLE POWER ADMINISTRATION**

P.O. Box 3621
Portland, Oregon 97208
(503) 230-3000

Stephen J. Wright, Administrator and Chief Executive Officer
Steven G. Hickok, Deputy Administrator and Deputy Chief Executive Officer
Ruth B. Bennett, Chief Operating Officer (Acting)
Randy A. Roach, General Counsel
James H. Curtis, Chief Financial Officer

**SPECIAL COUNSEL TO BONNEVILLE POWER ADMINISTRATION**

Orrick, Herrington & Sutcliffe LLP
New York, New York

**FINANCIAL ADVISOR TO BONNEVILLE POWER ADMINISTRATION**

Public Financial Management, Inc.
New York, New York

NO DEALER, BROKER, SALESPERSON OR OTHER PERSON HAS BEEN AUTHORIZED BY THE DISTRICT OR THE UNDERWRITERS TO GIVE ANY INFORMATION OR TO MAKE ANY REPRESENTATIONS OTHER THAN THOSE CONTAINED IN THIS OFFICIAL STATEMENT AND, IF GIVEN OR MADE, SUCH OTHER INFORMATION OR REPRESENTATIONS MUST NOT BE RELIED UPON AS HAVING BEEN AUTHORIZED BY ANY OF THE FOREGOING. THIS OFFICIAL STATEMENT, WHICH INCLUDES THE COVER PAGE AND APPENDICES, DOES NOT CONSTITUTE AN OFFER TO SELL OR THE SOLICITATION OF AN OFFER TO BUY, NOR SHALL THERE BE ANY SALE OF THE 2003 BONDS BY ANY PERSON IN ANY JURISDICTION IN WHICH IT IS UNLAWFUL FOR SUCH PERSON TO MAKE SUCH OFFER, SOLICITATION OR SALE.

THE INFORMATION SET FORTH HEREIN HAS BEEN OBTAINED FROM THE DISTRICT AND BONNEVILLE AND CONTAINS INFORMATION FROM OTHER SOURCES WHICH ARE BELIEVED TO BE RELIABLE, BUT IT IS NOT GUARANTEED AS TO ACCURACY OR COMPLETENESS AND IS NOT TO BE CONSTRUED AS A REPRESENTATION BY THE UNDERWRITERS. THE UNDERWRITERS HAVE REVIEWED THE INFORMATION IN THIS OFFICIAL STATEMENT IN ACCORDANCE WITH, AND AS PART OF, THEIR 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. THE INFORMATION HEREIN IS 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 DISTRICT OR BONNEVILLE SINCE THE DATE HEREOF.

IN CONNECTION WITH THE OFFERING OF THE 2003 BONDS, THE UNDERWRITERS MAY OVER ALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2003 BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

THE ACHIEVEMENT OF CERTAIN RESULTS IN THIS OFFICIAL STATEMENT OR OTHER EXPECTATIONS CONTAINED IN FORWARD-LOOKING STATEMENTS INVOLVES KNOWN AND UNKNOWN RISKS, UNCERTAINTIES AND OTHER FACTORS WHICH MAY CAUSE ACTUAL RESULTS, PERFORMANCE OR ACHIEVEMENTS DESCRIBED TO BE MATERIALLY DIFFERENT FROM ANY FUTURE RESULTS, PERFORMANCE OR ACHIEVEMENTS EXPRESSED OR IMPLIED BY SUCH FORWARD-LOOKING STATEMENTS. THE DISTRICT AND BONNEVILLE DO NOT PLAN TO ISSUE ANY UPDATES OR REVISIONS TO THOSE FORWARD-LOOKING STATEMENTS IF OR WHEN THEIR EXPECTATIONS OR EVENTS, CONDITIONS OR CIRCUMSTANCES ON WHICH SUCH STATEMENTS ARE BASED OCCUR.

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# PUBLIC UTILITY DISTRICT NO. 1
# OF LEWIS COUNTY, WASHINGTON

## OFFICIAL STATEMENT

## $146,210,000
## COWLITZ FALLS HYDROELECTRIC PROJECT
## REVENUE REFUNDING BONDS, SERIES 2003

### INTRODUCTORY STATEMENT

The purpose of this Official Statement, including its appendices, is to provide information concerning the Public Utility District No. 1 of Lewis County, Washington (the "District") Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 (the "2003 Bonds"). The 2003 Bonds will be issued pursuant to (1) Resolution No. 2245 approved June 19, 2003 (the "Bond Resolution") authorizing the issuance of the 2003 Bonds for purposes of refunding the outstanding Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991 (the "1991 Bonds") and Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 1993 (the "1993 Bonds") (collectively the "Refunded Bonds") and (2) Title 54 RCW and chapter 39.53 RCW. Unless otherwise specifically defined, certain capitalized terms used in this Official Statement have the meanings given to such terms in the Bond Resolution. See APPENDIX B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution."

The proceeds of the 2003 Bonds will be used to provide funds necessary to refund the 1991 Bonds and the 1993 Bonds and to pay the costs of issuance of the 2003 Bonds. See "PURPOSE OF THE 2003 BONDS AND APPLICATION OF THE 2003 BOND PROCEEDS."

In 1991, Bonneville Power Administration ("Bonneville") entered into a Power Purchase Contract with the District under which Bonneville is acquiring all of the output of the Project through June 30, 2032 (the "Power Purchase Contact"). Pursuant to the Power Purchase Contract, Bonneville is obligated to pay all Project Power Costs (as defined in the Power Purchase Contract), including debt service on the 2003 Bonds, whether or not the Cowlitz Falls Project is terminated, operating or operable. Bonneville also entered into a Payment Agreement with the Trustee in 1991 under which Bonneville is further obligated to pay debt service on the 2003 Bonds if it does not make such payments under the Power Purchase Contract. The Power Purchase Contract and the Payment Agreement are referred to as the "Bonneville Agreements." See APPENDIX E — "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT."

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 are constructed and 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. Bonneville sells and 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. See "THE BONNEVILLE POWER ADMINISTRATION."

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.

The District is a municipal corporation under the constitution and laws of the State of Washington. The District was organized in 1936 pursuant to a general election and commenced operation in 1939. The District has its administrative offices in Chehalis, Washington and is governed by a three-member Board of Commissioners. In addition to the Cowlitz Falls Project, the District also owns and operates an electric distribution system (the "Electric System"), which is financed and accounted for separately from the Cowlitz Falls Project. The Electric System serves substantially all of Lewis County, Washington, except the City of Centralia. See "THE DISTRICT."

This Official Statement includes summaries of the terms of the 2003 Bonds, the Bond Resolution, and the Bonneville Agreements. The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, report or instrument.

This introduction is qualified in its entirety by reference to the entire Official Statement and a full review of the Official Statement should be made by potential investors. This Official Statement speaks only as of its date and the information contained in it is subject to change.

## PURPOSE OF THE 2003 BONDS AND APPLICATION OF THE 2003 BOND PROCEEDS

### PURPOSE OF THE 2003 BONDS

Proceeds of the 2003 Bonds will be used to refund the outstanding 1991 Bonds and 1993 Bonds in order to effect a debt service savings and to pay the costs of issuance of the 2003 Bonds. To accomplish this refunding, proceeds of the 2003 Bonds will be used to provide the payment of principal and interest on all of the outstanding $24,685,000 of the 1991 Bonds and $138,530,000 of the 1993 Bonds (together, the "Refunded Bonds"). The 1991 Bonds shall be called for redemption at a price of 100% approximately 30 days from closing of the 2003 Bonds and the 1993 Bonds shall be called for redemption at a price of 102% on October 1, 2003.

Proceeds of sale of the 2003 Bonds shall be credited to the Refunding Account, which is to be drawn upon for the sole purpose of paying the principal of and interest on the Refunded Bonds on their respective dates of redemption and of paying costs related to the refunding of the Refunded Bonds. Money in the Refunding Account shall be used immediately upon receipt to defease the Refunded Bonds and to pay costs of issuance of the 2003 Bonds.

The District shall defease the Refunded Bonds and discharge such obligations by the use of money in the Refunding Account to purchase certain Government Obligations (referred to as "Acquired Obligations"), bearing such interest and maturing as to principal and interest in such amounts and at such times which, together with any necessary beginning cash balance, will provide payment of: (1) interest on the Refunded Bonds due and payable on their respective redemption dates and (2) the redemption price of (100% or 102%, as applicable) of the principal amount of the Refunded Bonds as provided herein.

### VERIFICATION OF MATHEMATICAL CALCULATIONS

The accuracy of (1) the mathematical computations as to the adequacy of the principal of and interest on the Acquired Obligations to be purchased and held by U.S. Bank National Association (the "Escrow Agent") to pay the redemption price of and interest on the Refunded Bonds as described above, and (2) the mathematical computations supporting the conclusion of Bond Counsel that the 2003 Bonds are not "arbitrage bonds" under Section 148 of the Internal Revenue Code of 1986, as amended, will be verified by Grant Thornton LLP, a firm of independent certified public accountants.

## SECURITY FOR THE 2003 BONDS

### PLEDGE OF COWLITZ FALLS REVENUES

The 2003 Bonds are special limited obligations of the District payable from and secured solely by a lien and charge on (i) the proceeds of the sale of the 2003 Bonds to the extent held in the funds established under the Bond Resolution; (ii) Cowlitz Falls Revenues, which include income, revenues, receipts and profits derived by the District in connection with the Cowlitz Falls Project, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Project and certain other money, including amounts paid by Bonneville under the Power Purchase Contract, exclusive of any payments under the Payment Agreement, certain insurance proceeds, and income pledged to the defeasance of specific revenue bonds (see Appendix B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution" for the complete definition of Cowlitz Falls Revenues); and (iii) the money and assets, if any, credited to the Revenue Fund, the Bond Fund, any junior lien fund or account created pursuant to the Bond Resolution, in each case excluding amounts required to be rebated to the federal government. Such items are pledged as security for the payment of the principal of, redemption premium, if any, and interest on the 2003 Bonds in accordance with the provisions of the Bond Resolution, subject only to the provisions restricting or permitting the application thereof for the purposes and on the terms and conditions set forth in the Bond Resolution. The 2003 Bonds are further secured by payments, if any, made by Bonneville to the Trustee pursuant to the Payment Agreement. Revenues do not include any payments, if any, made by Bonneville to the Trustee pursuant to the Payment Agreement. THE COWLITZ FALLS BONDS ARE NOT PAYABLE FROM, OR SECURED BY ANY LIEN ON, OR ANY INCOME DERIVED BY THE DISTRICT THROUGH THE OWNERSHIP AND OPERATION OF THE ELECTRIC SYSTEM OR ANY OTHER GENERATION, TRANSMISSION OR DISTRIBUTION FACILITIES THAT MAY BE PURCHASED, CONSTRUCTED OR OTHERWISE ACQUIRED BY THE DISTRICT AS A SEPARATE SYSTEM.

The outstanding 2003 Bonds and bonds issued on a parity therewith (the "Additional Bonds") shall be equally and ratably payable and secured under the Bond Resolution without priority, except as otherwise expressly provided or permitted in the Bond Resolution and except as to proceeds of credit enhancements which may be obtained by the District to assure the repayment of one or more series or maturities within a series.

### POWER PURCHASE CONTRACT

The District and Bonneville entered into the Power Purchase Contract to provide for the acquisition, construction, improvement and operation of the Cowlitz Falls Project and to provide for the sale of the electric power to be generated by the Cowlitz Falls Project. The original Power Purchase Contract became effective January 28, 1991, was restated effective May 23, 1991, and terminates on June 30, 2032. See Appendix E — "SUMMARY OF CERTAIN PROVISIONS OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT" for a summary of certain of the provisions of the Bonneville Agreements and defined terms used herein.

In the Power Purchase Contract, the District agrees to sell and deliver, and Bonneville agrees to purchase and accept delivery of, the entire Project output during the Term of the Power Purchase Contract. Bonneville has agreed to pay during each Operating Year an amount equal to Cowlitz Falls Project Power Costs, including debt service on the Cowlitz Falls Bonds, whether or not the Project or any part thereof has been completed, terminated, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance of any party or for any cause. In accordance with the Bond Resolution and the Bonneville Agreements, Bonneville shall pay to the Trustee amounts sufficient to pay principal of, premium, if any, and interest on the Bonds. Such payments shall be made solely from the Bonneville Fund. See "THE "BONNEVILLE POWER ADMINISTRATION — Bonneville Financial Operations — The Bonneville Fund." In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville, including a breach of the Power Purchase Contract, is a judgment for money damages.

Cowlitz Falls Project Power Costs means, with respect to each month, an amount equal to all costs attributable to the Cowlitz Falls Project, to the extent not paid from the proceeds of Cowlitz Falls Bonds or any other sources, resulting from the ownership, operation, maintenance and improvement of the Cowlitz Falls Project. The District is not obligated and does not expect to pay Cowlitz Falls Project Power Costs from Electric System Revenues.

**PAYMENT AGREEMENT**

If, and to the extent that, Bonneville does not make payments of principal of, interest on, and premium, if any, on the 2003 Bonds under the Power Purchase Contract at the time and in the manner described in the Power Purchase Contract, Bonneville shall make payments under the Payment Agreement not later than the dates on which such payments are described by the Power Purchase Contract. To the extent the amounts required to be paid under the Bond Resolution as principal and interest on the 2003 Bonds will not be available in the Bond Fund to be paid when due, Bonneville shall make such payments to the Trustee for benefit of the bondholders. Such payments are to be made only from the Bonneville Fund as described herein or from such other fund as shall now or hereafter become lawfully available for such purposes. See "SOURCE OF BONNEVILLE'S PAYMENTS: THE BONNEVILLE FUND." Bonneville agrees in the Payment Agreement that its obligations and the rights of the Trustee and the bondowners under the Payment Agreement shall not be terminated, impaired, or otherwise affected by any action taken, or not taken, by the District, the Trustee, any bondowner or any other party. The Payment Agreement remains in full force and effect whether or not the Project or any part thereof has been completed, terminated, is operating or operable or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. The Trustee has the authority to enforce the provisions of the Payment Agreement and to protect the interest of the bondowners in the manner provided by law. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville, including a breach of the Payment Agreement, is a judgment of money damages. The Payment Agreement remains in full force and effect without impairment of any of Bonneville's obligations until the date on which all Bonds and Additional Bonds have been paid or defeased in accordance with the Bond Resolution. See APPENDIX E — "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT."

**SOURCE OF BONNEVILLE'S PAYMENTS: THE BONNEVILLE FUND**

Payments by Bonneville under the Bonneville Agreements are to be made from the Bonneville Fund, into which flow all of Bonneville's receipts, collections and other recoveries of Bonneville in cash from all sources, subject to the limitations on the use of such Fund. **Bonneville's payment obligations under the Bonneville Agreements are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.**

The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more compete discussion of the Bonneville Fund, see "BONNEVILLE POWER ADMINISTRATION — Bonneville Financial Operations — The Bonneville Fund."

Bonneville may make expenditures from the Bonneville Fund, which expenditures 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.

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 2002 payment responsibility to the United States Treasury in full and on time.

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 payments with respect to the 2003 Bonds 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 cash payments of Bonneville, including payments with respect to the 2003 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) to (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.

Bonneville also has a substantial number of agreements with Preference Customers, as hereinafter described, pursuant to which Bonneville provides credits against power and transmission purchases made from Bonneville by such customers. Under these "net billing" agreements, related Bonneville Preference Customers ("Participants") make payments to two third parties (Energy Northwest and the City of Eugene, Oregon, Water and Electric Board ("EWEB")) to meet the costs of several nuclear generating projects. In return, Bonneville provides to the Participants payment credits against the monthly power and transmission bills issued by Bonneville. Subject to certain limitations and exceptions, the net billing credits are provided in amounts equivalent to the payments the Participants make to the third parties. Once the Participants have satisfied their payment obligations to the third parties in a related net billing agreement contract year, and Bonneville has provided the Participants equivalent dollar amounts of credits in such year, the 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 net billing agreements, although it is possible that the third parties may reinitiate net billing in a contract year to cover unexpected costs.

The net billing arrangements have had and are expected to have the effect of reducing Bonneville's revenues in cash during early portions of Bonneville's fiscal year since Bonneville does not realize a substantial amount of payments in cash from its power and transmission sales to the Participants. As a group, Participants constitute Bonneville's largest customer base. The period in a 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 Participants, and on the costs of the related projects.

For additional descriptions of Bonneville's substantial net billing arrangements, see "BONNEVILLE POWER ADMINISTRATION -- Power Business Line — Description of the Generation Resources of the Federal System — Energy Northwest's Net Billed Projects — Net Billing Agreements" and "Bonneville's Financial Operations — Statement of Net Billing Obligations and Expenditures."

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) net billed project costs 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 payments by Bonneville under the Bonneville Agreements, but excluding payments to the United States Treasury and (3) payments to the United States Treasury.

For further information, see "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 "BONNEVILLE FINANCIAL OPERATIONS — Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

**FLOW OF FUNDS**

The District has covenanted that so long as any of the Cowlitz Falls Bonds are outstanding and unpaid it will continue to pay into the Revenue Fund all Cowlitz Falls Revenues, except for payments made directly by Bonneville to the Trustee pursuant to the Power Purchase Contract or the Payment Agreement (which payments will be deposited directly into the Bond Fund), and any other money required to be paid into the Revenue Fund pursuant to the Bond Resolution. So long as any Cowlitz Falls Bonds remain outstanding, the amounts on deposit in the General Account in the Revenue Fund and the Bond Fund, as applicable, shall be used only for the following purposes and in the following order of priority:

(i) to make all payments required to be made into the Interest Account in the Bond Fund;

(ii) to make all payments required to be made into the Principal Account in the Bond Fund;

(iii) to make all payments required to be made into the Reserve Account in the Bond Fund, including reimbursing the provider for any draws on Qualified Insurance or a Qualified Letter of Credit;

(iv) to pay Operation and Maintenance Costs;

(v) to make all payments required to be made into any junior lien fund or account; and

(vi) to make any payments required to be made into the Reserve and Contingency Account in the Revenue Fund.

After all of the above payments and credits have been made, amounts remaining in the General Account may be used for any of the following purposes: (i) for transfer to any other fund or account created under the Bond Resolution; (ii) for the purchase or redemption of any Cowlitz Falls Bonds; (iii) to pay any subordinated indebtedness of the Cowlitz Falls Project; (iv) to pay Other Renewal and Replacement Costs; or (v) for any lawful corporate purpose of the District; provided that during the Term of the Bonneville Agreements all surplus amounts in the General Account shall be used for the Cowlitz Falls Project as directed by Bonneville.

**RESERVE ACCOUNT**

A Reserve Fund is established in the Bond Fund in order to provide a reserve for the payment of the principal, premium, if any, and interest on the 2003 Bonds. The Reserve Account will not be funded for the 2003 Bonds. For a summary of the Reserve Account, see APPENDIX B — “SUMMARY OF THE BOND RESOLUTION — Reserve Account.”

**ADDITIONAL BONDS**

The District has no current plans to issue any Additional Bonds. The Bond Resolution permits the issuance of Additional Bonds payable from Cowlitz Falls Revenues on a parity with the 2003 Bonds upon compliance with the following conditions:

1. That when such Additional Bonds are issued there is no deficiency in the Bond Fund or in any of the accounts therein and no Event of Default has occurred and is continuing; and

2. There shall be on file a certified copy of the Supplemental Resolution authorizing the issuance of such Additional Bonds; and

3. Bonneville shall have approved the issuance of the Additional Bonds; and

4. Either (a) debt service on the whole of the Additional Bonds is payable as a Project Power Cost under the Power Purchase Agreement for at least the term of the Power Purchase Agreement (or the final maturity date of such Additional Bonds if such maturity date shall occur earlier than the end of such term), or (b) debt service on the whole of the Additional Bonds is not payable as a Project Power Cost under the Power Purchase Agreement

and that, except for refunding Bonds where there is a debt service savings in each year (as to which no report of the Consulting Engineer is required), there shall have been delivered to the Trustee and the District a report of a Consulting Engineer, to the effect that the plan pursuant to which the proceeds of such Bonds are to be expended is consistent with prudent utility practice and will not adversely materially interfere with the operations of the Cowlitz Falls Project and that in the opinion of the Consulting Engineer, based on such assumptions as he believes to be reasonable, such plan will not result in a reduction of Cowlitz Falls Revenues below the amount sufficient for the payment of Cowlitz Falls Project Power Costs, after crediting against such costs amounts paid from the Reserve and Contingency Account or from Recovery Payments or other insurance proceeds; and

5. There shall be on file an opinion of Bond Counsel that the Additional Bonds are validly issued and constitute an enforceable and binding obligation of the District, except as such enforceability may be limited by laws affecting the rights of creditors or equitable principles.

With the consent of Bonneville, the District may enter into Derivative Products under which its payment obligations are on a parity with the 2003 Bonds. See APPENDIX B — "SUMMARY OF THE BOND RESOLUTION — Additional Bonds."

**COVENANTS**

For a summary of certain covenants of the District, see APPENDIX B — "SUMMARY OF THE BOND RESOLUTION — Covenants."

## DESCRIPTION OF THE 2003 BONDS

**DESCRIPTION**

The 2003 Bonds will be dated their date of delivery to the initial purchaser thereof and will be issued in the aggregate principal amount of $146,210,000. The 2003 Bonds will mature on the dates and in the principal amounts and will bear interest at the respective rates as shown on the cover page of this Official Statement. The 2003 Bonds will be issued as registered bonds in multiples of $5,000 within a single maturity and will be in a book-entry only system, initially registered in the name of Cede & Co., as nominee for The Depository Trust Company ("DTC"), New York, New York. See APPENDIX D — "BOOK-ENTRY SYSTEM." Interest on the 2003 Bonds will be paid on October 1, 2003, and semiannually thereafter on each April 1 and October 1 to maturity or prior redemption. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

**BOND REGISTRAR**

The principal of, interest on, and redemption premium of, if any, the 2003 Bonds are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Bond Registrar"). For so long as the 2003 Bonds remain in a "book-entry only" transfer system, the Bond Registrar will make such payments to DTC, which, in turn, is obligated to remit such principal and interest to the DTC participants for subsequent disbursement to the Beneficial Owners of the 2003 Bonds as further described in APPENDIX D — "BOOK-ENTRY SYSTEM."

The District and Bonneville have appointed U.S. Bank National Association, a national banking association organized under the laws of the United States, to serve as Trustee. The Trustee is to carry out those duties assignable to it under the Bond Resolution. Except for the contents of this section, the Trustee has not reviewed or participated in the preparation of this Official Statement and assumes no responsibility for the contents, accuracy, fairness or completeness of the information set forth in this Official Statement or for the recitals contained in the Bond Resolution or the 2003 Bonds, or for the validity, sufficiency, or legal effect of any of such documents.

The Trustee has not evaluated the risks, benefits, or propriety of any investment in the 2003 Bonds and makes no representation, and has reached no conclusions, regarding the value or condition of any assets or revenues pledged or assigned as security for the 2003 Bonds, or the investment quality of the 2003 Bonds, about all of which the Trustee expresses no opinion and expressly disclaims the expertise to evaluate.

Additional information about the Trustee may be found at its website at http://www.usbank.com/corporatetrust. The U.S. Bank website is not incorporated into this Official Statement by such reference and is not a part hereof.

**REDEMPTION**

***Optional Redemption***. The 2003 Bonds maturing on and after October 1, 2014, will be subject to redemption prior to maturity at the option of the District, with the consent of Bonneville, as a whole at any time or in part on any interest payment date on or after October 1, 2013 at par plus accrued interest, if any, to the redemption date.

If less than all the 2003 Bonds subject to optional redemption are so called for redemption, the District, with the consent of Bonneville, shall choose the maturities or sinking fund amounts and years, as applicable, to be redeemed. If less than all of the 2003 Bonds of an entire maturity are to be redeemed, the 2003 Bonds of such maturity to be redeemed shall be selected according to the operational arrangements of DTC if the 2003 Bonds are held by DTC or, if the 2003 Bonds are not held by DTC, by the Bond Registrar randomly; provided, the remaining 2003 Bonds Outstanding after any redemption must be in authorized denominations.

***Partial Redemption***. If less than all of the principal amount of any 2003 Bond is redeemed, upon surrender of such Bond at the principal office of the Bond Registrar, there shall be issued to the registered owner, without charge, for the then unredeemed balance of the principal amount, a new Bond or Bonds, at the option of the registered owner, of like maturity and interest rate in any authorized denomination.

***Notice of Redemption***. Notice of any redemption of 2003 Bonds shall be given by the Bond Registrar on behalf of the District by first class mail, postage prepaid, not less than 30 days nor more than 60 days before the redemption date to the registered owners of 2003 Bonds that are to be redeemed at their last addresses shown on the Bond Register. So long as the 2003 Bonds are in book-entry form, notice of redemption shall be given as provided in the Letter of Representations. The Bond Registrar shall provide additional notice of redemption (at least 30 days) to each NRMSIR and SID, if any, and unless the District has revoked a notice of redemption, the District shall transfer to the Bond Registrar amounts that, in addition to other money, if any, held by the Bond Registrar, will be sufficient to redeem, on the redemption date, all the Bonds to be redeemed. From the redemption date interest on each Bond to be redeemed shall cease to accrue.

**PURCHASES FOR CANCELLATION**

The District has reserved the right to purchase the 2003 Bonds for cancellation at any price with the consent of Bonneville.

**TRANSFER AND REGISTRATION**

The registered ownership of any 2003 Bond may be transferred or exchanged, but no transfer of any 2003 Bond shall be valid unless it is surrendered to the Bond Registrar with the assignment form appearing on such 2003 Bond duly executed by the Registered Owner or such Registered Owner's duly authorized agent in a manner satisfactory to the Bond Registrar. Upon such surrender, the Bond Registrar shall cancel the surrendered 2003 Bond and shall authenticate and deliver, without charge to the Registered Owner or transferee, a new 2003 Bond (or 2003 Bonds at the option of the new Registered Owner) of the same date, maturity and interest rate and for the same aggregate principal amount in any authorized denomination, naming as Registered Owner the person or persons listed as the assignee on the assignment form appearing on the surrendered 2003 Bond, in exchange for such surrendered and canceled 2003 Bond. Any 2003 Bond may be surrendered to the Bond Registrar and exchanged, without charge, for an equal aggregate principal amount of 2003 Bonds of the same date, maturity and interest rate, in any authorized denomination. The Bond Registrar shall not be obligated to transfer or exchange any 2003 Bond during a period beginning at the opening of business on the 15th day of the month next preceding any interest payment date and ending at the close of business on such interest payment date, or, in the case of any proposed redemption of the 2003 Bonds, after the mailing of notice of the call of such 2003 Bonds for redemption.

## PROCEDURE IN THE EVENT OF REVISIONS OF BOOK-ENTRY TRANSFER SYSTEM

In the event that (a) DTC or its successor (or substitute depository or its successor) resigns from its functions as depository, and no substitute depository can be obtained, or (b) the District determines that it is in the best interest of the beneficial owners of the 2003 Bonds that the 2003 Bonds be provided in certificated form, the ownership of such 2003 Bonds may then be transferred to any person or entity as herein provided, and shall no longer be held in fully immobilized form. The District shall deliver a written request to the Bond Registrar, together with a supply of definitive 2003 Bonds in certificated form, to issue 2003 Bonds in any authorized denomination. Upon receipt by the Bond Registrar of all then outstanding 2003 Bonds, together with a written request on behalf of the District to the Bond Registrar, new 2003 Bonds shall be issued in the appropriate denominations and registered in the names of such persons as are provided in such written request. Thereafter, the principal of the 2003 Bonds shall be payable upon presentment and surrender thereof at the principal office of the Bond Registrar, interest on the 2003 Bonds will be payable by check or draft mailed to the persons in whose names such 2003 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date, and the 2003 Bonds will be transferable as described above; *provided*, however, if so requested in writing by the Registered Owner of at least $1,000,000 principal amount of 2003 Bonds, interest will be paid by wire transfer on the due date to an account with a bank located in the United States.

## BOND INSURANCE

### XL CAPITAL ASSURANCE INC.

Payment of the principal of and interest on $3,050,000 of the 2003 Bonds maturing in 2007 and the 2003 Bonds maturing in 2008 through 2012 (the "XLCA-Insured Bonds") will be insured by a municipal bond insurance policy to be issued by XL Capital Assurance Inc. simultaneously with the delivery of the 2003 Bonds. The following information has been supplied by XL Capital Assurance Inc. ("XLCA") for inclusion in this Official Statement. No representation is made by the District as to the accuracy or completeness of the information. Reference is made to Appendix G for a specimen of XLCA's policy.

XLCA accepts no responsibility for the accuracy or completeness of this Official Statement or any other information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding XLCA and its affiliates set forth under this heading. In addition, XLCA makes no representation regarding the 2003 Bonds or the advisability of investing in the 2003 Bonds.

***General.*** XLCA is a monoline financial guaranty insurance company incorporated under the laws of the State of New York. XLCA is currently licensed to do insurance business in, and is subject to the insurance regulation and supervision by, the State of New York, forty-seven other states, the District of Columbia, Puerto Rico, the U.S. Virgin Islands and Singapore. XLCA has license applications pending, or intends to file an application, in each of those states in which it is not currently licensed.

XLCA is an indirect wholly owned subsidiary of XL Capital Ltd, a Cayman Islands corporation ("XL Capital Ltd"). Through its subsidiaries, XL Capital Ltd is a leading provider of insurance and reinsurance coverages and financial products to industrial, commercial and professional service firms, insurance companies and other enterprises on a worldwide basis. The common stock of XL Capital Ltd is publicly traded in the United States and listed on the New York Stock Exchange (NYSE: XL). XL Capital Ltd is not obligated to pay the debts of or claims against XLCA.

XLCA was formerly known as The London Assurance of America Inc. ("London"), which was incorporated on July 25, 1991 under the laws of the State of New York. On February 22, 2001, XL Reinsurance America Inc. ("XL Re") acquired 100% of the stock of London. XL Re merged its former financial guaranty subsidiary, known as XL Capital Assurance Inc. (formed September 13, 1999) with and into London, with London as the surviving entity. London immediately changed its name to XL Capital Assurance Inc. All previous business of London was 100% reinsured to Royal Indemnity Company, the previous owner at the time of acquisition.

***Reinsurance.*** XLCA has entered into a facultative quota share reinsurance agreement with XL Financial Assurance Ltd ("XLFA"), an insurance company organized under the laws of Bermuda, and an affiliate of XLCA. Pursuant to this reinsurance agreement, XLCA expects to cede up to 90% of its business to XLFA. XLCA may also cede reinsurance to third parties on a transaction-specific basis, which cessions may be any or a combination of quota share, first loss or excess of loss. Such reinsurance is used by XLCA as a risk management device and to comply with statutory and rating agency requirements and does not alter or limit XLCA's obligations under any financial guaranty insurance policy. With respect to any transaction insured by XLCA, the percentage of risk ceded to XLFA may be less than 90% depending on certain factors including, without limitation, whether XLCA has obtained third party reinsurance covering the risk. As a result, there can be no assurance as to the percentage reinsured by XLFA of any given financial guaranty insurance policy issued by XLCA, including the XLCA Bond Insurance Policy.

Based on the audited financials of XLFA, as of December 31, 2002, XLFA had total assets, liabilities, redeemable preferred shares and shareholders' equity of $611,791,000, $245,750,000, $39,000,000 and $327,041,000, respectively, determined in accordance with generally accepted accounting principles in the United States. XLFA's insurance financial strength is rated "Aaa" by Moody's and "AAA" by S&P and Fitch Inc. In addition, XLFA has obtained a financial enhancement rating of "AAA" from S&P.

The obligations of XLFA to XLCA under the reinsurance agreement described above are unconditionally guaranteed by XL Insurance (Bermuda) Ltd ("XLI"), a Bermuda company and one of the world's leading excess commercial insurers. XLI is a wholly owned indirect subsidiary of XL Capital Ltd. In addition to having an "A+" rating from A.M. Best, XLI's financial strength rating is "Aa2" by Moody's and "AA" by Standard & Poor's and Fitch. The ratings of XLFA and XLI are not recommendations to buy, sell or hold securities, including the XLCA-Insured Bonds and are subject to revision or withdrawal at any time by Moody's, Standard & Poor's or Fitch.

Notwithstanding the capital support provided to XLCA described in this section, the holders of the XLCA-Insured Bonds will have direct recourse against XLCA only, and neither XLFA nor XLI will be directly liable to the holders of the XLCA-Insured Bonds.

***Financial Strength and Financial Enhancement Ratings of XLCA***. XLCA's insurance financial strength is rated "Aaa" by Moody's and "AAA" by Standard & Poor's and Fitch, Inc. ("Fitch"). In addition, XLCA has obtained a financial enhancement rating of "AAA" from Standard & Poor's. These ratings reflect Moody's, Standard & Poor's and Fitch's current assessment of XLCA's creditworthiness and claims-paying ability as well as the reinsurance arrangement with XLFA described under "Reinsurance" above. The above ratings are not recommendations to buy, sell or hold securities, including the XLCA-Insured Bonds, and are subject to revision or withdrawal at any time by Moody's, Standard & Poor's or Fitch. Any downward revision or withdrawal of these ratings may have an adverse effect on the market price of the XLCA-Insured Bonds. XLCA does not guaranty the market price of the XLCA-Insured Bonds nor does it guaranty that the ratings on the XLCA-Insured Bonds will not be revised or withdrawn.

***Capitalization of XLCA.*** Based on the audited statutory financial statements for XLCA as of December 31, 2001, XLCA had total admitted assets of $158,442,157, total liabilities of $48,899,461 and total capital and surplus of $109,542,696 determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities ("SAP"). Based on the unaudited statutory financial statements for XLCA as of December 31, 2002 filed with the State of New York Insurance Department, XLCA has total admitted assets of $180,993,189, total liabilities of $58,685,217 and total and capital surplus of $122,307,972 determined in accordance with SAP.

For further information concerning XLCA and XLFA, see the financial statements of XLCA and XLFA, and the notes thereto, incorporated by reference in this Official Statement. The financial statements of XLCA and XLFA are included as exhibits to the periodic reports filed with the Securities and Exchange Commission (the "Commission") by XL Capital Ltd and may be reviewed at the EDGAR website maintained by the Commission. All financial statements of XLCA and XLFA included in, or as exhibits to, documents filed by XL Capital Ltd pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities and Exchange Act of 1934 on or prior to the date of this Official Statement, or after the date of this Official Statement but prior to termination of the offering of the 2003 Bonds, shall be deemed incorporated by reference in this Official Statement. Except for the financial statements of XLCA and XLFA, no other information contained in XL Capital Ltd's reports filed with the Commission is incorporated by reference. Copies of the statutory quarterly and annual statements filed with the State of New York Insurance Department by XLCA are available upon request to the State of New York Insurance Department.

***Regulation of XLCA.*** XLCA is regulated by the Superintendent of Insurance of the State of New York. In addition, XLCA is subject to regulation by the insurance laws and regulations of the other jurisdictions in which it is licensed.

As a financial guaranty insurance company licensed in the State of New York, XLCA is subject to Article 69 of the New York Insurance Law, which, among other things, limits the business of each insurer to financial guaranty insurance and related lines, prescribes minimum standards of solvency, including minimum capital requirements, establishes contingency, loss and unearned premium reserve requirements, requires the maintenance of minimum surplus to policyholders and limits the aggregate amount of insurance which may be written and the maximum size of any single risk exposure which may be assumed. XLCA is also required to file detailed annual financial statements with the New York Insurance Department and similar supervisory agencies in each of the other jurisdictions in which it is licensed.

The extent of state insurance regulation and supervision varies by jurisdiction, but New York and most other jurisdictions have laws and regulations prescribing permitted investments and governing the payment of dividends, transactions with affiliates, mergers, consolidations, acquisitions or sales of assets and incurrence of liabilities for borrowings.

THE FINANCIAL GUARANTY INSURANCE POLICIES ISSUED BY XLCA, INCLUDING THE XLCA-INSURED BONDS INSURANCE POLICY, ARE NOT COVERED BY THE PROPERTY/CASUALTY INSURANCE SECURITY FUND SPECIFIED IN ARTICLE 76 OF THE NEW YORK INSURANCE LAW.

The principal executive offices of XLCA are located at 1221 Avenue of the Americas, New York, New York 10020 and its telephone number at this address is (212) 478-3400.

**MBIA INSURANCE CORPORATION**

Payment of the principal of and interest on the 2003 Bonds maturing in 2013 through 2024 (the "MBIA-Insured Bonds") will be insured by a municipal bond insurance policy to be issued by MBIA Insurance Corporation simultaneously with the delivery of the 2003 Bonds. The following information has been furnished by MBIA Insurance Corporation ("MBIA") for use in this Official Statement. Reference is made to Appendix H for a specimen of MBIA's policy.

MBIA's policy unconditionally and irrevocably guarantees the full and complete payment required to be made by or on behalf of the District to the Bond Registrar or its successor of an amount equal to (i) the principal of (either at the stated maturity or by an advancement of maturity pursuant to a mandatory sinking fund payment) and interest on, the MBIA-Insured Bonds as such payments shall become due but shall not be so paid (except that in the event of any acceleration of the due date of such principal by reason of mandatory or optional redemption or acceleration resulting from default or otherwise, other than any advancement of maturity pursuant to a mandatory sinking fund payment, the payments guaranteed by MBIA's policy shall be made in such amounts and at such times as such payments of principal would have been due had there not been any such acceleration); and (ii) the reimbursement of any such payment which is subsequently recovered from any owner of the MBIA-Insured Bonds pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such owner within the meaning of any applicable bankruptcy law (a "Preference").

MBIA's policy does not insure against loss of any prepayment premium which may at any time be payable with respect to any MBIA-Insured Bonds. MBIA's policy does not, under any circumstance, insure against loss relating to: (i) optional or mandatory redemptions (other than mandatory sinking fund redemptions); (ii) any payments to be made on an accelerated basis; (iii) payments of the purchase price of MBIA-Insured Bonds upon tender by an owner thereof; or (iv) any Preference relating to (i) through (iii) above. MBIA's policy also does not insure against nonpayment of principal of or interest on the MBIA-Insured Bonds resulting from the insolvency, negligence or any other act or omission of the Bond Registrar or any other paying agent for the MBIA-Insured Bonds.

Upon receipt of telephonic or telegraphic notice, such notice subsequently confirmed in writing by registered or certified mail, or upon receipt of written notice by registered or certified mail, by MBIA from the Bond Registrar or any owner of MBIA-Insured Bonds the payment of an insured amount for which is then due, that such required payment has not been made, MBIA on the due date of such payment or within one business day after receipt of notice of such nonpayment, whichever is later, will make a deposit of funds, in an account with U.S. Bank Trust National Association, in New York, New York, or its successor, sufficient for the payment of any such insured amounts which are then due. Upon presentment and surrender of such MBIA-Insured Bonds or presentment of such other proof of ownership of the MBIA-Insured Bonds, together with any appropriate instruments of assignment to evidence the assignment of the insured amounts due on the MBIA-Insured Bonds as are paid by MBIA, and appropriate instruments to effect the appointment of MBIA as agent for such owners of the MBIA-Insured Bonds in any legal proceeding related to payment of insured amounts on the MBIA-Insured Bonds, such instruments being in a form satisfactory to U.S. Bank Trust National Association, U.S. Bank Trust National Association shall disburse to such owners or the Bond Registrar payment of the insured amounts due on such MBIA-Insured Bonds, less any amount held by the Bond Registrar for the payment of such insured amounts and legally available therefor.

***MBIA.*** MBIA is the principal operating subsidiary of MBIA Inc., a New York Stock Exchange listed company (the "Company"). The Company is not obligated to pay the debts of or claims against MBIA. MBIA is domiciled in the State of New York and licensed to do business in and subject to regulation under the laws of all 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, the Virgin Islands of the United States and the Territory of Guam. MBIA has three branches, one in the Republic of France, one in the Republic of Singapore and one in the Kingdom of Spain. New York has laws prescribing minimum capital requirements, limiting classes and concentrations of investments and requiring the approval of policy rates and forms. State laws also regulate the amount of both the aggregate and individual risks that may be insured, the payment of dividends by MBIA, changes in control and transactions among affiliates. Additionally, MBIA is required to maintain contingency reserves on its liabilities in certain amounts and for certain periods of time.

MBIA does not accept any responsibility for the accuracy or completeness of this Official Statement or any information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding the policy and MBIA set forth under this subsection heading "MBIA INSURANCE CORPORATION." Additionally, MBIA makes no representation regarding the 2003 Bonds or the advisability of investing in the 2003 Bonds.

The Financial Guarantee Insurance Policies are not covered by the Property/Casualty Insurance Security Fund specified in Article 76 of the New York Insurance Law.

***MBIA Information.*** The following documents filed by the Company with the Securities and Exchange Commission (the "SEC") are incorporated herein by reference:

(1) The Company's Annual Report on Form 10-K for the year ended December 31, 2002; and

(2) The Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003.

Any documents filed by the Company pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act of 1934, as amended, after the date of this Official Statement and prior to the termination of the offering of the MBIA-Insured Bonds offered hereby shall be deemed to be incorporated by reference in this Official Statement and to be a part hereof. Any statement contained in a document incorporated or deemed to be incorporated by reference herein, or contained in this Official Statement, shall be deemed to be modified or superseded for purposes of this Official Statement to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. Any such statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Official Statement.

The Company files annual, quarterly and special reports, information statements and other information with the SEC under File No. 1-9583. Copies of the SEC filings (including (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2002, and (2) the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003), are available (i) over the Internet at the SEC's web site at http://www.sec.gov; (ii) at the SEC's public reference room in Washington D.C.; (iii) over the Internet at the Company's web site at http://www.mbia.com; and (iv) at no cost, upon request to MBIA Insurance Corporation, 113 King Street, Armonk, New York 10504. The telephone number of MBIA is (914) 273-4545.

As of December 31, 2002, MBIA had admitted assets of $9.2 billion (audited), total liabilities of $6.0 billion (audited), and total capital and surplus of $3.2 billion (audited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities. As of March 31, 2003, MBIA had admitted assets of $9.3 billion (audited), total liabilities of $6.1 billion (audited), and total capital and surplus of $3.2 billion (audited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities.

***Financial Strength Ratings of MBIA.*** Moody's Investors Service rates the financial strength of MBIA "Aaa."

Standard & Poor's, a division of The McGraw-Hill Companies, Inc. rates the financial strength of MBIA "AAA."

Fitch Ratings rates the financial strength of MBIA "AAA."

Each rating of MBIA should be evaluated independently. The ratings reflect the respective rating agency's current assessment of the creditworthiness of MBIA and its ability to pay claims on its policies of insurance. Any further explanation as to the significance of the above ratings may be obtained only from the applicable rating agency.

The above ratings are not recommendations to buy, sell or hold the MBIA-Insured Bonds, and such ratings may be subject to revision or withdrawal at any time by the rating agencies. Any downward revision or withdrawal of any of the above ratings may have an adverse effect on the market price of the MBIA-Insured Bonds. MBIA does not guaranty the market price of the MBIA-Insured Bonds nor does it guaranty that the ratings on the MBIA-Insured Bonds will not be revised or withdrawn.

## DEBT SERVICE REQUIREMENTS

Upon issuance of the 2003 Bonds and the simultaneous refunding of the 1991 Bonds and the 1993 Bonds, the District will not have any other debt of the Cowlitz Falls Project. Debt service on the 2003 Bonds is set forth below.

| Year | Principal Amount | Interest* | Total Annual Debt Service* |
|---|---|---|---|
| 2003 | | $ 1,499,673 | $ 1,499,673 |
| 2004 | | 7,198,431 | 7,198,431 |
| 2005 | $ 3,700,000 | 7,198,431 | 10,898,431 |
| 2006 | 4,700,000 | 7,013,431 | 11,713,431 |
| 2007 | 4,930,000 | 6,778,431 | 11,708,431 |
| 2008 | 5,110,000 | 6,600,556 | 11,710,556 |
| 2009 | 5,360,000 | 6,345,056 | 11,705,056 |
| 2010 | 5,630,000 | 6,077,056 | 11,707,056 |
| 2011 | 5,915,000 | 5,795,556 | 11,710,556 |
| 2012 | 6,215,000 | 5,499,806 | 11,714,806 |
| 2013 | 6,520,000 | 5,189,056 | 11,709,056 |
| 2014 | 6,850,000 | 4,863,056 | 11,713,056 |
| 2015 | 7,190,000 | 4,520,556 | 11,710,556 |
| 2016 | 7,545,000 | 4,161,056 | 11,706,056 |
| 2017 | 7,930,000 | 3,783,806 | 11,713,806 |
| 2018 | 8,325,000 | 3,387,306 | 11,712,306 |
| 2019 | 8,740,000 | 2,971,056 | 11,711,056 |
| 2020 | 9,175,000 | 2,534,056 | 11,709,056 |
| 2021 | 9,635,000 | 2,075,306 | 11,710,306 |
| 2022 | 10,120,000 | 1,593,556 | 11,713,556 |
| 2023 | 11,035,000 | 1,087,556 | 12,122,556 |
| 2024 | 11,585,000 | 535,806 | 12,120,806 |
| TOTALS | $ 146,210,000 | $ 96,708,604 | $ 242,918,604 |

* Totals may not add due to rounding.

## THE COWLITZ FALLS PROJECT

### DESCRIPTION OF THE COWLITZ FALLS PROJECT

The Cowlitz Falls Project was built on the upper Cowlitz River in eastern Lewis County, Washington, approximately one mile below the confluence of the Cispus River and the Cowlitz River and upstream from the existing Mayfield and Mossyrock hydroelectric projects owned and operated by the City of Tacoma, Washington. The dam and power generation facility were completed in 1994. The dam is 140 feet high and spans approximately 700 feet across the Cowlitz River. A reservoir behind the dam has a surface area of approximately 610 acres. The powerhouse contains two vertical Kaplan-type turbine units connected to two synchronous generators, each with a rated capacity of approximately 35 megawatts, at an average net head of approximately 87.5 feet. The Cowlitz Falls Project is operated essentially as a "run-of-river" hydroelectric facility, and daily variations in the water surface elevation of the reservoir are not expected to exceed two feet under normal operating conditions.

In June 1986, the District was granted a 50-year license by the Federal Energy Regulatory Commission ("FERC") to construct and operate the Cowlitz Falls Project. The license expires on June 1, 2036.

### COWLITZ FALLS PROJECT OUTPUT

The Cowlitz Falls Project has minimal storage capability. Consequently, it is operated essentially as a "run-of-river" hydroelectric facility. The amount of energy generated by the Cowlitz Falls Project is affected by a number of factors, including natural stream flows and FERC requirements. Estimates of expected energy generation at hydroelectric power projects in the Pacific Northwest for planning purposes are generally based on historical stream flows which occurred over the longest period for which historical stream flow records are available. Based on a 57-year period (1928 through 1985) of historical stream flow records which the District used for planning purposes, the annual energy output of the Cowlitz Falls Project would have varied from a low of approximately 136,000 megawatt-hours based on stream flows which occurred in 1941 to a high of approximately 375,000 megawatt-hours based on stream flows which occurred in 1956. The average annual energy output (including non-firm energy) of the Cowlitz Falls Project which would have been produced during the 57-year period is approximately 261,000 megawatt-hours.

## COWLITZ FALLS PROJECT ANNUAL COSTS

The following table sets forth the amount of power and cost of power from the Cowlitz Falls Project which was delivered to Bonneville at the point of delivery in 1999 to 2002 and the 2003 budget information.

**Cowlitz Falls Project Output and Annual Cost of Power**
**($000)**

| | 1999 | 2000 | 2001 | 2002 | 2003 Budget(10) |
|---|---|---|---|---|---|
| PROJECT POWER COSTS | | | | | |
| Operation and Maintenance Expenses: | | | | | |
| Operation(1) | $ 553 | $ 672 | $ 591 | $ 520 | $ 430 |
| Maintenance(1) | 552 | 395 | 374 | 234 | 282 |
| Administrative and General | 429 | 396 | 386 | 463 | 556 |
| Insurance | 79 | 94 | 79 | 158 | 140 |
| Taxes(2) | 43 | 368 | 110 | 120 | 102 |
| Transmission(3) | 165 | 165 | 165 | 165 | 165 |
| Renewals, Replacements and Repairs(4) | 0 | 0 | 0 | 0 | 0 |
| Subtotal | $ 1,821 | $ 2,090 | $ 1,705 | $ 1,660 | $ 1,675 |
| Debt Service on Bonds(5) | $13,054 | $13,052 | $13,055 | $13,053 | $13,053 |
| Less: Interest Earnings(6) | 938 | 923 | 909 | 895 | 850 |
| Net Debt Service | $12,116 | $12,129 | $12,146 | $12,158 | $12,203 |
| Total Project Power Costs | $13,937 | $14,219 | $13,851 | $13,818 | $13,878 |
| OTHER TRANSMISSION COSTS(7) | $ 730 | $ 766 | $ 740 | $ 334 | $ 630 |
| TOTAL ANNUAL COST OF PROJECT POWER TO BONNEVILLE | $14,667 | $14,985 | $14,591 | $14,152 | $14,508 |
| Net Energy Output Delivered to Bonneville (MWh)(8) | 324,147 | 203,495 | 181,586 | 230,332 | 261,000 |
| Average Net Energy Cost (cents/kWh)(9) | 4.52 | 7.36 | 8.03 | 6.14 | 5.56 |

(1) The District currently is not capitalizing any expenditures and records expenses as incurred.
(2) In 2000 the State of Washington assessed privilege taxes on the generation output. Prior to 2000 privilege taxes were not accrued, thus a lump sum was paid in 2000 for tax liability for 1999-2000 and taxes accrued thereafter. This amount also includes other taxes incurred by the Project.
(3) Costs incurred from transmission over the District's lines pursuant to a contract.
(4) Ordinary Renewals, Replacements and Repairs are considered Operation or Maintenance items as incurred. No costs are projected to be capitalized in the foreseeable future.
(5) Includes Debt Service on the 1991 and 1993 Bonds, which is paid pursuant to an amortization schedule and includes principal and interest.
(6) Interest earnings are from funds placed in the reserve account for the 1991 Bonds and the 1993 Bonds according to bond covenants.
(7) The District's annual costs of wheeling the Project output from the Glenoma substation to the Bonneville transmission system. Transmission costs in 2002 were reduced because of a credit for prior over payments.
(8) Annual changes are primarily due to variations in stream-flow.
(9) Average net cost to Bonneville at the point of delivery.
(10) Bonneville and the District recently changed the Cowlitz Falls Project's operating year to correspond with Bonneville's fiscal year. Consequently, the 2003 Budget reflects 14 months. For the purposes of this table, however, the budget has been revised to reflect 12 months of data. The District's independent accountants, Moss Adams LLP, have no association with this table.

## TRANSMISSION OF COWLITZ FALLS PROJECT OUTPUT

Cowlitz Falls Project output is delivered from the Project switchyard to the Bonneville point of delivery over a five mile 230 kV transmission line from the Project switchyard to the District's Glenoma substation, then over a 15 mile 230-kV transmission line from the Glenoma substation to an existing switchyard owned by the City of Tacoma (Mossyrock switchyard) at the Mossyrock Dam site, and finally from the Mossyrock switchyard over existing transmission facilities of the City of Tacoma to the Bonneville point of delivery, which is located approximately six miles from the Mossyrock switchyard.

## ENVIRONMENTAL ISSUES

The National Marine Fisheries Service ("NMFS"), now known as the National Oceanographic and Atmospheric Administration — Fisheries ("NOAA Fisheries"), has listed the lower Columbia Chinook salmon and steelhead trout as threatened under the Endangered Species Act ("ESA"). The Cowlitz River is a tributary of the lower Columbia River and the Cowlitz Falls Project operates on the Cowlitz. As a result of the Cowlitz Falls Project operation and the ESA anadromous fish listings, the District has initiated consultation with the FERC and NOAA Fisheries to evaluate possible ESA impacts on the Project. This consultation is expected to lead toward a permitted taking of the threatened species for the Project. This process will likely result in certain undetermined costs related to Project operation and mitigation provisions.

On January 14, 2000, American Rivers, Trout Unlimited and Friends of the Cowlitz filed a Notice of Intent to Sue for Violations of the ESA. The Notice claims the FERC, Bonneville and the District are violating the ESA by continued operation of the Cowlitz Falls Project. American Rivers indicates that unless Bonneville and FERC initiate consultation under Section 7 of the ESA with NOAA Fisheries regarding the impact of the Project on listed species and unless immediate action is taken to bring the Project into compliance, they will file suit against the FERC, Bonneville and the District. Should American Rivers file suit, and should a reviewing court find that the Project is not operated in compliance with the ESA, it is possible that additional mitigation measures could be required by NOAA Fisheries. Such measures could increase the cost of the Project. As described above, the District has initiated consultation with FERC and NOAA Fisheries.

# THE DISTRICT

## GENERAL

Public Utility District No. 1 of Lewis County is a municipal corporation of the State of Washington. The District was organized in 1936 pursuant to a general election in accordance with Title 54 RCW and commenced its operations in 1939. The District's service territory is comprised of approximately 2,530 square miles in Lewis County, Washington, as well as a portion of southeastern Pierce County in the vicinity of Mt. Rainier National Park. The District does not serve the City of Centralia, which is located in Lewis County. The District's administrative offices are located at 321 N.W. Pacific Avenue, P.O. Box 330, Chehalis, Washington 98532.

Pursuant to Washington statutes, the District is administered by a Board of Commissioners (the "Commission") of three elected members. The legal responsibilities and powers of the District, including the establishment of rates and charges for services rendered, are exercised through the Commission. The Commission establishes policy, approves plans, budgets and expenditures and reviews the District's operations. Under present law, the District has the exclusive authority to set rates and charges for electric energy and services and is by law free from the rate-making jurisdiction and control of the Washington Utilities and Transportation Commission or any other state, federal or local agency having the authority to set rates and charges for electric energy and services. The District has the power of eminent domain.

The present Commissioners of the District, their titles and the expiration dates of their respective terms of office are as follows:

| Name | Title | Expiration of Term of Office December 31, |
|---|---|---|
| Charles R. TenPas | President | 2004 |
| James H. Hubenthal | Vice President | 2006 |
| John L. Kostick | Secretary | 2008 |

***Charles R. TenPas***, President, was appointed to the Commission in June 1995 and is serving his second term on the Commission. Mr. TenPas currently serves as the District's representative to the Washington Public Utility District Association and is a retired public school teacher and administrator.

***James Hubenthal***, Vice President, was re-elected to his fourth term on the Commission in November 2000. Mr. Hubenthal had previously served on the Commission from 1982 through 1988 and from 1991 to the present.

***John L. Kostick***, Secretary, was elected to the Commission in 1978 and is currently serving his fifth term as a Commissioner being reelected in November 2002. Mr. Kostick is a retired businessman and cattle rancher.

**MANAGEMENT AND ADMINISTRATION**

The principal staff members of the District are as follows:

***David J. Muller***, Manager, joined the District in 1972. Mr. Muller holds a BS degree in agricultural engineering from Washington State University and is a Licensed Professional Engineer (Electrical) in the State of Washington. Previously, Mr. Muller served as the District's Chief Engineer beginning in 1978.

***Rich Bauer***, Treasurer/Controller, joined the District in 2000. Prior to joining the District, Mr. Bauer was the Auditor/Office Manager of Public Utility District No. 1 of Ferry County, Washington. Mr. Bauer holds a BS degree in accounting from Central Washington University, BA degree in Business Administration from Western Washington University and is certified under the Laws of the State of Washington as a Certified Public Accountant.

***James R. Haselwood***, Auditor, joined the District in 1977. Prior to joining the District, Mr. Haselwood was an assistant manager and accountant with a savings and loan company in Chehalis, Washington. Mr. Haselwood has an Associates of Art degree from Centralia College.

***Ronald D. Raff***, Superintendent, joined the District in 1976. Prior to joining the District, Mr. Raff worked for Public Utility District No. 1 of Cowlitz County, Washington. He came to the District in 1976 as the local manager in Morton, Washington. Mr. Raff holds a BSEE degree from the University of Washington and is a Licensed Professional Engineer (Electrical) in the State of Washington. Mr. Raff is retiring July 31, 2003.

**LABOR RELATIONS**

The District has two separate agreements with the International Brotherhood of Electrical Workers ("IBEW"), one covering the non-staff employees of the Electric System and a second covering the non-staff employees of the Cowlitz Falls Project. The term of the Electric System agreement with the IBEW is three years and expires on April 1, 2006. The Cowlitz Falls Project agreement with the IBEW is also three years and expires on February 1, 2004.

**UTILITY OPERATIONS**

The District's electric utility properties and operations presently consist of two separate systems, each of which is accounted for and financed separately. The systems are (1) the Electric System, which includes the electric utility properties and assets used generally in transmitting and distributing electric energy at retail and (2) the Cowlitz Falls Project (see "THE COWLITZ FALLS PROJECT").

The Electric System's operations, maintenance and capital additions are financed from revenues received from the sale of electricity. The Electric System has no outstanding debt. The Electric System's net utility plant as of December 31, 2002 was $83,157,778. In 2002, the Electric System had revenues of $38,277,686, net income of $1,601,547 and retained earnings of $102,082,772.

In September 2000, the District signed a new ten-year power purchase contract with Bonneville. The contract became effective on October 1, 2011. Under this contract, the District will purchase substantially all of its power requirements from Bonneville. The District owns, operates, and utilizes the power from a small 600 kW hydroelectric project (Mill Creek) and purchases the output from a small 560 kW hydroelectric project (Burton Creek) which is owned and operated by an independent power producer. In 2000, the Mill Creek and Burton Creek Projects produced approximately 0.3% of the District's total energy requirements. The District has signed a power purchase agreement with Energy Northwest for 2% (one MW of capacity) of the output of the Nine Canyon Wind Project, which began commercial operation in September 2002.

The District serves approximately 27,700 customers, of which more than 24,500 are residential. Historically, Lewis County's economy has been based on the timber and agricultural industries. In recent years, Lewis County's employment has experienced a transition toward governmental services, retail trade and service industries generally related to Interstate Highway 5 that crosses the western part of Lewis County. Today, the District's retail sales consist of approximately 51% residential, 23% industrial, 18% commercial, and 8% public and governmental authorities. In 2002, the Hampton Lumber Company, which operates two mills in eastern Lewis County, was the District's largest customer, purchasing approximately 42,500 MWh or 5.6% of the District's total sales.

**INSURANCE**

The District and 16 other public utility districts participate in a joint self-insurance pool ("Fund") in affiliation with Public Utility Risk Management Services ("PURMS"), formerly Washington Public Utility Districts' Utilities System ("WPUDUS"). The PURMS Fund self insures its members to $500,000 for liability and maintains a reserve of at least $1,000,000. Members of the PURMS Fund are automatically assessed to make up any shortfall in the reserve amount. General comprehensive liability insurance in excess of $500,000 is insured through Associated Electric and Gas Insurance Services Limited in the amount of $35 million. Public officials' errors and omissions liability is issued to the District in the amount of $4,500,000 in excess of the $500,000 self-insurance fund. The PURMS Fund and its members are involved in ongoing litigation and claim processing of which the total dollar value of the risk posed is unknown. Currently, the Cowlitz Falls Project is insured separate from the Electric System through Factory Mutual Insurance Company (FM Global). The dam structure is insured to $100,000,000 along with other coverage for operating activities and liabilities.

## BONNEVILLE POWER ADMINISTRATION

The information in this section has been furnished to the District by Bonneville for use in this Official Statement. Such information is not to be construed as a representation by or on behalf of the District or the Underwriters. The District 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 2003 Bonds, Bonneville will certify to the District that the information in this section, as well as information pertaining to Bonneville contained elsewhere in this 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 section and elsewhere in this 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 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 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin, and from several non-federally owned and operated projects including the Columbia Generating Station. 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. 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"), including the District, for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to about six 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 historical levels.

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. Bonneville remains a single legal entity, but it now 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 Columbia River Power System (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 2002 payment responsibility to the United States Treasury in full and on time. For more information, see "BONNEVILLE FINANCIAL OPERATIONS — Order in Which Bonneville's Costs Are Met."

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 payments relating to the 2003 Bonds 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 make payments to the United States Treasury only from net proceeds: all cash payments of Bonneville, including cash payments relating to the 2003 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) to (iv) above.

## 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. Prices declined in fiscal year 2002, although they have risen somewhat in the current fiscal year. 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 and Power Rates for Fiscal Years 2002-2006

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 investor-owned utilities ("Regional IOUs") to whom Bonneville is required by law to provide Residential Exchange Program benefits, as hereinafter described, expired. In anticipation of the expiration of such contracts and during the unprecedented volatility in Western power markets described herein, 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 eight 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 resources and contract purchases, which was estimated at the time to be roughly 8000 average megawatts. 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 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 or will occur 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 now believes that its firm resources, including existing Augmentation Purchases, are roughly equal to its expected firm load obligations in fiscal years 2004 through 2006 and that Bonneville may have somewhat more firm resources than firm loads for the remainder of fiscal year 2003, depending on the month. Bonneville therefore believes that it will not have to make substantial additional Augmentation Purchases, if any, to meet its Subscription loads through at least fiscal year 2006, subject to changes in contracted loads or generation from Federal System generating resources, and subject to the receipt of power under Augmentation Purchases and other power purchase and related agreements. If contracted loads, especially those of DSIs, drop from current contract levels (after taking into account load reduction agreements), Bonneville could have a firm energy surplus in fiscal years 2004-2006.

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 Rate Proposal”). The 2002 Final Power Rate Proposal is comprised of an initial filing with FERC for “base rates” and a subsequent filing with FERC setting forth certain rate level adjustment mechanisms.

The proposed “base rates” are subject to three intra-rate-period rate level adjustments that are triggered upon the occurrence of specified circumstances. The base rates proposed by Bonneville 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 adjustment mechanisms has had the effect of raising Bonneville’s rates substantially. 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.

The second rate level adjustment, the Financial Based Cost Recovery Adjustment Clause (“FB-CRAC”), provides one-year adjustments in rate levels in addition to the LB-CRAC. The FB-CRAC is intended to increase rate levels 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. The amount of revenues Bonneville can obtain under the FB-CRAC is limited to a maximum of between about $90 million and $115 million per fiscal year, depending on the fiscal year in which the FB-CRAC adjustment is used.

The third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause (“SN-CRAC”), enables Bonneville to increase rate levels in order to recover costs on a temporary basis if, at any time during the five year rate period, Bonneville (i) forecasts a 50 percent or greater probability of missing a payment to the United States Treasury or other creditor in the then current fiscal year or (ii) misses a scheduled payment to the United States Treasury or other creditor.

As described below, rate level increases under the LB-CRAC and FB-CRAC are currently in effect. Bonneville also has initiated actions that will lead to the formal process necessary to possibly increase rate levels under the SN-CRAC. Some Subscription contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms. 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 Rate Proposal.”

FERC granted interim approval of the 2002 Final Power Rate Proposal in September 2001 and Bonneville awaits a final order from FERC approving such rates. 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 Rate Proposal.”

### Bonneville's Fiscal Year 2002 Financial Results

While Bonneville had positive net revenues of $9.5 million in fiscal year 2002, an increase of approximately $347 million over fiscal year 2001, Bonneville estimates it had an operating loss of about $308 million after excluding the positive net revenue effects of extending the 2002 maturities of Energy Northwest net billed program debt under the Debt Optimization Proposal.

Through separate series of "net billing agreements" among Bonneville, numerous electric utility customers of Bonneville and Energy Northwest—a joint operating agency organized under the laws of the State Washington—Bonneville secures over $6 billion in Energy Northwest obligations issued in respect of two now-terminated nuclear generating stations and one operating nuclear generating station. Under the Debt Optimization Proposal, Bonneville and Energy Northwest extended and will extend the average maturities of certain portions of such debt. This has provided and is expected to provide Bonneville with cash flow flexibility to advance the amortization of Bonneville's Federal debt. See "Bonneville Financial Operations — Debt Optimization Proposal."

The debt restructuring increased cash flow to Bonneville in fiscal year 2002, thereby enabling Bonneville to make planned prepayments and planned amortization ahead of schedule of about $266 million in bonds issued by Bonneville to the United States Treasury and appropriated repayment obligations to the United States Treasury. The low net revenues in fiscal year 2002 occurred despite a power rate level increase of over 40 percent over prior rates for similar service, on average during fiscal year 2002. The rate level increase applicable in fiscal year 2002 was made under the LB-CRAC, which is designed for the limited purpose of recovering only the direct costs of power purchases and load reductions under identified contracts Bonneville entered into to meet the 3200-3300 megawatt load increment Bonneville assumed under the Subscription Strategy. The LB-CRAC was not designed to and does not assure recovery of all of Bonneville's costs. The two semi-annual net LB-CRAC adjustments in fiscal year 2002 were about 46 percent and 39 percent of base rates, respectively.

Several developments affected Bonneville's financial results in fiscal year 2002. The main reason for the low net revenues was lower than expected revenues from seasonal surplus energy sales. A substantial portion of Bonneville's power sales revenues, in some years up to 25 percent or more, is derived from the sale of seasonal surplus hydroelectric energy. Bonneville's 2002 Final Power Rate Proposal for the five years beginning October 1, 2001, is based on certain assumptions regarding expected revenues from the sale of seasonal surplus energy. In making seasonal surplus energy revenue projections to support the rate proposal, Bonneville assumed average hydroelectric generation and used price forecasts finalized in May 2001, at a time when prevailing West Coast market prices for electric power were about 20.0 cents per kilowatt-hour. Bonneville's rate case projections assumed that the average price it would receive in fiscal year 2002 for seasonal surplus sales would be about 5.7 cents per kilowatt hour. Contrary to these forecasts, prevailing West Coast wholesale energy prices declined, resulting in Bonneville's obtaining between about 2.0 to 2.5 cents per kilowatt-hour for its seasonal surplus energy in fiscal year 2002.

In addition, although Columbia River Basin precipitation levels in fiscal year 2002 returned from the historically low levels of fiscal year 2001 to the average levels upon which the forecasts in the rate case are based, actual hydroelectric generation was below average, primarily as a result of the effects of refilling reservoirs. In addition, spring runoff conditions resulted in Bonneville's having to sell more than expected amounts of seasonal surplus energy during periods of the year when prices typically are, and in fact were, relatively low. As a consequence of the foregoing factors, Bonneville's discretionary power sales revenues were roughly $670 million lower in fiscal year 2002 than Bonneville forecast in the final stages of developing the 2002 Final Power Rate Proposal.

The lower than average hydroelectric generation and lower than forecast prices also led to a lower than expected realization in fiscal year 2002 of United States Treasury repayment credits for certain fish and wildlife costs incurred by Bonneville. Bonneville receives such credits, which it counts as revenues, under section 4(h)(10)(C) of the Northwest Power Act. A portion of these expenses is for power purchases made by Bonneville that are attributable to the effects of hydroelectric system constraints for the benefit of fish. If power prices decline, the credits Bonneville obtains for such expenditures also decline. Other factors that contributed to Bonneville's 2002 financial results were increased costs from the agreements with Regional IOUs to settle Bonneville's Residential Exchange obligations and increases in other O&M expenses. 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."

As a result of the financial performance in fiscal years 2001 and 2002, Bonneville ended fiscal year 2002 with financial reserves of about $188 million. By contrast, Bonneville's financial reserves for the fiscal years ending September 30, 2000 and September 30, 2001 were about $811 million and $625 million, respectively. 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.

For a discussion of year-to-year financial results see "BONNEVILLE FINANCIAL OPERATIONS — Management Discussion of Operating Results."

**Fiscal Year 2003 Financial Developments**

The precipitation and snowpack conditions in the Columbia River Basin, which to a great degree determine the amount of hydroelectric power the Federal System can produce, reflect an improvement over forecasts prepared in March 2003, but remain at lower than average levels this fiscal year. May 2003 forecasts prepared outside of, but relied on by, Bonneville indicated that January 2003 through July 2003 runoff in the Columbia River Basin as measured at the Dalles Dam may be about 85 percent of average.

In view of Bonneville's fiscal year 2002 financial results, continuing, lower-than-forecast revenues from discretionary sales of electric power, and increasing costs in several areas, Bonneville has taken a number of steps to assure that its revenues are adequate to meet its costs through the remainder of the rate period. First, with indications in early calendar year 2002 that revenues from discretionary power sales would be lower than previously forecasted, Bonneville began reducing its costs substantially. It has continued to do so in fiscal year 2003. Through expense reductions, deferrals and other actions, Bonneville expects to improve its Power Business Line financial health by $350 million in aggregate over the fiscal year 2003-2006 period. Bonneville continues to explore additional cost reductions and deferrals.

Second, Bonneville triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2003. This rate level adjustment will allow Bonneville to recover about $90 million in additional revenues in fiscal year 2003, after taking into account certain effects related to the Slice of the System contracts described herein. See "— Power Business Line — Certain Statutes and other Matters Affecting Bonneville's Power Business Line — Power Marketing in the Period After Fiscal Year 2001." The FB-CRAC has the effect of raising the average rates for those power sales and related contracts to which the adjustment applies by about 11 percent over applicable base rates. In view of forecasts for the end of fiscal year 2003, Bonneville expects that the FB-CRAC will again be employed in fiscal year 2004, having roughly the same effect on rates and revenue, as is the case in fiscal year 2003. The rate level increases under the FB-CRAC are in addition to rate level increases in effect under the LB-CRAC. Bonneville set the net LB-CRAC adjustment at about 32 percent of base rates for the first six months of fiscal year 2003 and at about 39 percent of base rate for the second six months of the fiscal year.

Third, in February 2003, Bonneville notified its customers that it would initiate the formal rate procedures to potentially increase rate levels under the SN-CRAC. Under the SN-CRAC, Bonneville may adjust power rates an indeterminate amount to recover its costs if Bonneville forecasts a 50 percent or greater probability that it will miss a scheduled payment to the United States Treasury or other party in the then current fiscal year. In February 2003, Bonneville estimated that there would be a 74 percent probability that it would not meet in full its scheduled fiscal year 2003 payments to the United States Treasury.

On March 13, 2003, Bonneville published its initial proposal for the SN-CRAC rate level adjustment. The initial proposal called for a three-year variable SN-CRAC adjustment to be determined annually by reference to indicators of Bonneville's financial condition. The initial proposal for the SN-CRAC rate level adjustment was designed to recover an expected value of about $340 million to $370 million for each of the three fiscal years in which it is proposed to be in effect. Bonneville estimated that the proposed SN-CRAC rate level adjustment increase under the initial proposal would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels by an average of about 15.7 percent over fiscal year 2003 power rate levels.

In anticipation of issuing a final record of decision supporting Bonneville's final proposal for the SN-CRAC rate level adjustment, Bonneville released a draft record of decision on June 16, 2003. The draft record of decision indicates Bonneville's expected approach to the final proposal for the SN-CRAC rate level adjustment. In view of improved water conditions, better than expected revenues from surplus sales, and cost management actions, Bonneville now anticipates in its draft record of decision that it will propose an overall SN-CRAC rate level increase for fiscal years 2004-2006 that is less than the SN-CRAC rate level adjustment Bonneville initially proposed. Bonneville now anticipates that it will propose an SN-CRAC rate level adjustment that would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels in fiscal years 2004-2006 by an average of about 5 percent over current fiscal year 2003 levels. Bonneville expects to issue the final record of decision and the final SN-CRAC rate level adjustment rate proposal at the end of June or early July 2003.

The draft record of decision indicates that the SN-CRAC rate level adjustment for each fiscal year will be made on the basis of the Power Business Line's third quarter projected net revenues for that fiscal year. Thus, the final SN-CRAC rate level adjustment for fiscal year 2004 will be set in August 2003 and will depend upon further revenue and cost changes. Under the draft record of decision, certain costs in a number of major cost categories would be capped and would not be automatically recovered through the final proposed SN-CRAC rate level adjustment. The maximum revenue recoverable through the SN-CRAC in fiscal years 2004-2006 is capped at $320 million per year. In addition, under the draft record of decision, Bonneville would provide a refund to customers from previously collected revenue if Bonneville's Power Business Line accumulated net revenues exceed established threshold levels.

Assuming financial reserves at currently projected levels and an SN-CRAC rate level adjustment for the three fiscal years beginning October 1, 2003, as described in the draft record of decision, Bonneville expects it would have an 80 percent probability of meeting its annual payment responsibility to the United States Treasury in full and on time over the three fiscal year period beginning October 1, 2003.

Assuming an SN-CRAC adjustment such as Bonneville desribes in the draft record of decision and expected rate level adjustments in fiscal year 2004 under the FB-CRAC and LB-CRAC, Bonneville's average power rates would 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 herein, 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.

The final SN-CRAC adjustment to be proposed by Bonneville is being determined in a formal rate setting process and will be influenced by changes in forecasts, projections and rate design. In proposing a rate level increase under the SN-CRAC, Bonneville expects, among other things, that it will receive lower price levels for discretionary power sales and lower revenues from such sales in fiscal years 2004-2006 than Bonneville forecast in the final phases of developing the 2002 Final Power Rate Proposal. The final SN-CRAC proposal will also depend on many other factors including updated financial information, customer input on rate design and the exercise by Bonneville of its judgment about the appropriateness of various rate level increases.

Several of Bonneville's customers and customer groups have filed separate suits in the Ninth Circuit Court challenging Bonneville's decision to initiate proceedings necessary for implementing the SN-CRAC. These parties are seeking to set aside Bonneville's finding that the SN-CRAC has triggered. If successful, the litigation could result in a remand by the court to Bonneville of the decision that the conditions permitting Bonneville to adjust its power rates under the SN-CRAC have been met. The petitioners have not sought expedited review by or injunctive relief from the court in this matter.

Some of the cost reductions and deferrals and the commencement in October 2002 of the rate level increase under the FB-CRAC have impacts in fiscal year 2003. Nonetheless, based on Bonneville's updated quarterly review dated as of May 2003, Bonneville estimates that if current forecasts of costs, streamflows and discretionary power sales are realized, Bonneville would have net revenues of about negative $28 million in fiscal year 2003. This calculation excludes $356 million in positive net revenue arising from debt management actions under the Debt Optimization Proposal. The fiscal year end net revenue projection also excludes about $20 million in non-cash, mark-to-market accounting adjustments under the Financial Accounting Standards Board Statement of Accounting Standard No. 133. These forecasted results also incorporate a total of about $85 million in recently effected one time improvements to cash flows arising from (i) arrangements with Energy Northwest to apply funds from a settlement with a paying agent of certain original Net Billed Bonds to pay current Net Billed Project costs, and (ii) the use of surety bonds in lieu of reserve funds for certain series of Net Billed Project Bonds. In addition to the foregoing events, the May 2003 updated forecast reflects somewhat improved views of Columbia River basin precipitation levels, power marketing conditions and expense levels relative to prior quarterly forecast of anticipated fiscal year end net revenues. Given the many variables and assumptions upon which such forecasts are based, actual net revenues could differ substantially from those indicated in such forecasts.

Notwithstanding the possibility that Bonneville could have negative net revenues in the current fiscal year, and in view of the relatively low fiscal year 2003 starting reserve balance of $188 million, Bonneville intends to manage its finances to assure that the fiscal year 2003 ending reserve level balance will not be lower than between $100 million and $200 million. The possible financial tools Bonneville may rely on to assure adequate reserves to meet cash flow needs in early fiscal year 2004 include, among other items: (i) deferring all or a portion of planned early repayments and amortization of about $315 million in bonds issued by Bonneville to the United States Treasury and appropriations repayment obligations by Bonneville to the United States Treasury at the end of fiscal year 2003 in great part under the Debt Optimization Proposal, (ii) seeking access to short-term borrowing with the United States Treasury under Bonneville's existing borrowing authority, or (iii) deferring scheduled interest and/or principal payments to the United States Treasury, meaning planned payments to the United States Treasury as scheduled under applicable repayment criteria in contrast to the advance amortization payments described in clause (i). Whether and the extent to which Bonneville will rely on the foregoing financial tools will depend on financial performance through the remainder of fiscal year 2003. On the basis of its most recent quarterly review of May 2003, Bonneville now expects that it is much less likely to rely on short-term borrowing from the United States Treasury, deferral of early amortization under the Debt Optimization Proposal, or deferrals of Bonneville's United States Treasury repayments to meet its fiscal year end reserve level needs than Bonneville anticipated when it issued its quarterly report of March 2003.

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 2003-2006 will be at or near average market prices for such period based on similar power products. Bonneville believes that its Subscription Power rates will still 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.

## 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 67% 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 2003."

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 estimates that in Operating Year 2003, the Federal System, including firm energy purchases, is capable of producing about 10,300 average megawatts of firm energy.

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 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.

While Bonneville markets most of its energy on a firm basis, 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.

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. During median water years, the Federal System would generate seasonal surplus energy of about 2700 annual average megawatts, while in wet years the amount of such energy available may average in some months as much as 4300 annual average megawatts. In dry 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, 2002, Slice customers purchased from Bonneville, for their requirements, an aggregated 22.63 percent proportionate interest of the output of the Federal System. This purchase includes firm power and what would otherwise be seasonal surplus energy from the Federal System in the same proportion. See "Power Business Line — Power Marketing in the Period After Fiscal Year 2001 — Preference Customer Loads."

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 reflects measures under the biological opinions (and supplements thereto) issued with respect to the Federal System beginning in 1995, in each case under the Endangered Species Act ("ESA"), including measures from the 2000 Biological Opinion and a biological opinion issued by the U.S. Fish and Wildlife Service ("Fish and Wildlife Service") in 2000. As new biological opinions and similar constraints are introduced to the hydropower system, those changes will be reflected in the availability of Federal hydropower under all water conditions. See "— Certain Statutes and Other Matters Affecting Bonneville's Power Business Line — Fish and Wildlife."

*Other Generating Resources*

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station. The Columbia Generating Station has the largest capacity for energy production of the non-federal resources. 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 has increased substantially from prior years as Bonneville has 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 2003*

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 and stream flow 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 Flows") occurred in 1936-37, median water conditions ("Median Flows") occurred in 1957-58 and high water conditions ("High 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 2003, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Flows, Median Flows and High 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 and assumed plant capacity factors.

**Operating Federal System Projects For Operating Year 2003**[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 | 1941 | 33 | 5,325 | 3,041 | 2,378 | 1,872 |
| Hungry Horse | 1952 | 4 | 323 | 129 | 101 | 77 |
| Other Bureau Projects[6] | | 15 | 225 | 163 | 156 | 130 |
| **Total Bureau of Reclamation Projects** | | 52 | 5,873 | 3,333 | 2,635 | 2,079 |
| **United States Army Corps of Engineers Hydro Projects** | | | | | | |
| Chief Joseph | 1955 | 27 | 2,129 | 1,622 | 1,334 | 1,047 |
| John Day | 1968 | 16 | 1,888 | 1,376 | 1,065 | 768 |
| The Dalles including Fishway[7] | 1957 | 24 | 2,074 | 1,077 | 839 | 602 |
| Bonneville including Fishway | 1938 | 20 | 752 | 562 | 523 | 357 |
| McNary | 1953 | 14 | 935 | 711 | 697 | 551 |
| Lower Granite | 1975 | 6 | 485 | 439 | 323 | 212 |
| Lower Monumental | 1969 | 6 | 595 | 411 | 272 | 214 |
| Little Goose | 1970 | 6 | 752 | 440 | 321 | 209 |
| Ice Harbor | 1961 | 6 | 471 | 314 | 199 | 97 |
| Libby | 1975 | 5 | 533 | 297 | 223 | 166 |
| Dworshak | 1974 | 3 | 343 | 219 | 190 | 125 |
| Other Corps Projects[8] | | 20 | 396 | 294 | 268 | 223 |
| **Total Corps of Engineers Projects** | | 153 | 11,353 | 7,762 | 6,254 | 4,571 |
| **Total Bureau of Reclamation and Corps of Engineers Projects** | | 205 | 17,226 | 11,095 | 8,889 | 6,650 |
| **Non-Federally-Owned Projects** | | | | | | |
| The Columbia Generating Station[9] | 1984 | 1 | 1,150 | 877 | 877 | 877 |
| Other Non-Federal Projects[10] | | 18 | 96 | 181 | 169 | 167 |
| **Total Non-Federally-Owned Projects** | | 19 | 1,246 | 1,058 | 1,046 | 1,044 |
| **Total Bonneville Contract Purchases**[11] | | N/A | 2,440 | 2,560 | 2,560 | 2,560 |
| **Total Federal System Resources** | | 224 | 20,912 | 14,713 | 12,495 | 10,254 |

*Source: 2001 Pacific Northwest Loads and Resources Study, Bonneville, October 2002.*

(1) Operating Year 2003 is August 1, 2002 through July 31, 2003.
(2) January capacity is the maximum generation to be produced under Low 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 Flows in average megawatts of energy. The hydroregulation studies for this analysis contain measures from biological opinions from and after 1995.
(4) Median energy capability is the estimated amount of hydro energy to be produced using Median Flows in average megawatts of energy.

(5) Firm energy capability is the estimated amount of hydro energy to be produced using Low Flows in average megawatts of energy.
(6) Other Bureau Projects include: Palisades (1957), Anderson Ranch (1950), Chandler (1956), 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 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), Green Springs (1960), Hills Creek (1962), Lookout Point (1954) and Lost Creek (1975).
(9) Columbia Generating Station has a scheduled maintenance outage, which will affect its energy output.
(10) Other Non-Federal Projects include the following hydroelectric and other projects: Mission Valley's Big Creek (1981), Lewis County PUD's Cowlitz Falls (1994), the City of Idaho Falls' Idaho Falls Project (1982), the Western Generation Agency's James River Wauna Cogeneration Project (1996), 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 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, a share of Energy Northwest's Nine Canyon Wind Project, NWW Wind Power's Klondike Phase 1 wind project, Calpine's Fourmile Hill Geothermal project, and a share of the City of Ashland's solar project.
(11) Bonneville Contract Purchases include: Subscription Strategy Augmentation Purchases and other contracts by Bonneville for power from both inside and outside the Region, including Canada.

*Energy Northwest's Net Billed Projects*

Set forth below is a description of certain nuclear generating stations undertaken by Energy Northwest, a joint operating agency formed under the laws of the State of Washington. Bonneville has acquired the entire project capability of Energy Northwest's Project 1 and Columbia Generating Station. Bonneville has also acquired all of the project capability associated with Energy Northwest's 70% ownership interest in Project 3. The Columbia Generating Station is an operating facility but Project 1 and Project 3 were terminated in the 1990s, prior to construction completion. These three projects are referred to as the "Net Billed Projects." Bonneville has also acquired the entire project capability associated with the City of Eugene, Oregon, Water and Electric Board's ("EWEB") 30% ownership interest in the now terminated Trojan Nuclear Project ("Trojan"), operated by and co-owned with Portland General Electric Company. The costs of the foregoing projects are secured by payments and net billing credits from Bonneville, as described herein.

Net Billing Agreements. Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (the "Project 3 Net Billing Agreements" which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project.

Each Project 1, Columbia and Project 3 Participant assigned its share of Project capability to Bonneville under a Project 1 Net Billing Agreement, Columbia Net Billing Agreement and Project 3 Net Billing Agreement, respectively.

Under the Net Billing Agreements, in payment for the share of the capability of each Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement or accounting statement. Bonneville is obligated to pay this amount to such Participant by providing net billing credits against the amounts such Participant owes Bonneville under the Participant's power sales and other contracts with Bonneville and by making the cash payments. Each Participant is obligated to pay Energy Northwest an amount equal to the amount of such credits and cash payments as payment on account of its obligations to pay for its share of the Net Billed Project capability.

Cash payments and the provision of credits by Bonneville and payments by Participants under the Net Billing Agreements are required whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Net Billed Project output or termination of the related Net Billed Project and 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 Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

Net Billed Projects. The Columbia Generating Station ("Columbia") is an operating nuclear electric generating station located about 160 miles southeast of Seattle, Washington, near Richland, Washington on the U.S. Department of Energy's ("DOE") Hanford Reservation. The site has been leased from DOE for a term of 50 years commencing July 1, 1972, with options to extend the lease for two consecutive ten-year periods.

Columbia commenced commercial operation in 1984 and has a net design electrical rating of 1,153 megawatts. Columbia consists of a General Electric Company-designed boiling water reactor and nuclear steam supply system, a Westinghouse turbine-generator and the necessary transformer, switching and transmission facilities to deliver the output to the transmission facilities of the Federal System located in the vicinity of Columbia. The entire capability of Columbia has been acquired by Bonneville under the Columbia Net Billing Agreements.

Project 1 is a terminated, partially completed nuclear electric generating project located about 160 miles southeast of Seattle, Washington, on DOE's Hanford Reservation, approximately one and one-half miles east of Columbia. In May 1994, Energy Northwest's Board of Directors adopted a resolution terminating Project 1. After termination, Energy Northwest proceeded to offer for sale assets in the form of uninstalled operating equipment and construction materials in light of the fact that there was no market for the sale of Project 1 in its entirety. Certain of these assets have been sold. Energy Northwest has been planning for the demolition of Project 1 and restoration of the site.

Project 3 is a terminated, partially complete nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington. In May 1994, Energy Northwest's Board of Directors adopted a resolution requesting the termination of Project 3. Project 3 was terminated in June 1994. Virtually all of the remaining project assets have been sold and the site ownership has been transferred to a county development entity.

Site Restoration of Project 1. Energy Northwest's Project 1 shares a common site lease from DOE with Energy Northwest's terminated Nuclear Project No. 4 (Project 4). Project 4 is one of two generating stations for which Energy Northwest (formerly, Washington Public Power Supply System) issued bonds that were subsequently unpaid and placed in default when the Washington State Supreme Court found that certain underlying contracts among various utility participants (not including Bonneville) were invalid under Washington State law. Since Project 4 has virtually no assets to fund site restoration and because it shares a common site lease with Project 1, there is some uncertainty in the view of the Washington State Energy Facilities Siting Council ("EFSEC") about the legal responsibility that Project 1 may have for Project 4 site restoration.

Site restoration requirements for Projects 1 and 4 are governed by site certification agreements between Energy Northwest and the State of Washington and regulations adopted by EFSEC and a lease agreement with DOE. Energy Northwest submitted a site restoration plan to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment or other techniques such that the sites pose minimal hazard to the public. EFSEC conditionally approved the site restoration plan on June 12, 1995.

Bonneville, Energy Northwest, EFSEC and DOE have negotiated a proposed agreement concerning site restoration for Projects 1 and 4. Bonneville, DOE, and Energy Northwest have signed the proposed agreement and await a signature by an authorized official representing EFSEC. The proposed agreement would require that Bonneville fund site remediation of Projects 1 and 4 in return for a commitment on a level of site remediation that is less expensive than maximum level of site restoration considered by EFSEC. The total cost of the level of remediation under the proposed agreement has been estimated at $45 million (calendar year 2003 dollars).

With the exception of near-term remediation compatible with reuse (approximately $3 million to $4 million expended within 24 months of approval of the remediation plan by EFSEC), assuming execution and delivery of the agreement by all parties, Bonneville would probably defer the remediation obligation for about 20 years as permitted by the proposed agreement, leaving the sites and the structures available for potential reuse.

To meet its proposed financial commitment for remediation, Bonneville expects to place funds in a separate interest-bearing trust account in order to have sufficient funds for the eventual final remediation. Bonneville's site remediation obligation, if reuse of the sites and structures does not occur, would not be conditioned on the adequacy of funds in the trust account.

### 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 (including the District) within the Region, are entitled to a statutory preference and priority (the "Public Preference") in the purchase of available Federal System power. These customers are eligible to purchase power at Bonneville's "Priority Firm Rate" (or, "PF Rate") for most of their loads, and as a class are Bonneville's principal customer base. Under the 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.

Some Regional public bodies served by Regional IOUs are now seeking to form public body utilities to qualify as Preference Customers and obtain priority access to electric power from Bonneville. These public bodies include municipalities and port districts. Under the Subscription process, Bonneville received conforming requests from and signed contingent contracts with four such entities. Under Subscription, about 75 average megawatts of firm power at the Priority Firm rates were reserved for, and are now provided to, such new entities.

#### *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" and "BONNEVILLE FINANCIAL OPERATIONS — Historical Federal System Financial Data."

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 authorized Bonneville to sell for export out of the Region a limited amount of power unencumbered to a degree 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 after October 1, 2001. Bonneville does not expect to have substantial new amounts of such excess federal power to sell during the five-year rate period beginning October 1, 2001. See "BONNEVILLE LITIGATION — M-S-R Public Power Agency, *et al.*, v. Bonneville Power Administration."

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 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*

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 have resulted in concerns by energy suppliers that the Cal-ISO may not be a creditworthy supplier, and led to the intervention by the State of California as purchaser of electric power to supply consumers served by the Cal-IOUs.

The second 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 $90 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 has initiated two separate 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 both proceedings.

In the first proceeding, FERC is reviewing 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. In this proceeding, FERC has concluded that unjust and unreasonable pricing in fact occurred. FERC bifurcated the proceeding and conducted a hearing before an Administrative Law Judge (ALJ) in March 2002 to determine a pricing structure that approximates a competitive market. FERC, through the ALJ, conducted a second hearing in August 2002 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. On December 12, 2002, the ALJ issued Proposed Findings related to the March and August phases of the hearing. The Proposed Findings are subject to review by FERC. The exact amount of any refund liability and a determination of who owes what to whom will be determined in a compliance filing that is yet to be scheduled. Despite the issuance of the Proposed Findings, Bonneville cannot predict with any accuracy the amount of refund liability against Bonneville because the actual calculation must be determined through the settlement computer systems of the Cal-ISO and Cal-PX. However, based upon prior calculations of refund liability and the impact of the Proposed Findings on these earlier calculations, Bonneville believes that the amount of any refunds determined by FERC against Bonneville would be substantially less than the unpaid amounts owed to Bonneville by the Cal-PX and the Cal-ISO. Under prior rulings by FERC, this should result in a net payment owed to Bonneville.

In the second proceeding, FERC is reviewing 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. FERC has indicated that if it were to find that power sellers exacted unjust and unreasonable prices during this period, FERC would undertake a subsequent proceeding to determine refund liability.

FERC held a hearing in early September 2001 in this proceeding. On September 24, 2001, the presiding judge 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 presiding 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. FERC has not yet ruled on the presiding judge's recommendations.

While Bonneville is a participant in the foregoing refund proceedings, Bonneville has taken the position before FERC in certain petitions for rehearing that FERC has no jurisdiction over Bonneville in this matter under the Federal Power Act, 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 nonjurisdictional utilities' petitions. Several nonjurisdictional utilities, including Bonneville, have filed appeals in Federal appellate court.

In a related matter, on February 13, 2002, FERC announced that it was initiating an investigation by FERC staff into 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. The order directing the investigation does not specify the remedial actions that FERC may implement or attempt to implement in the event it were to conclude that price manipulation or undue influence over prices in fact occurred. See "— Effect on Bonneville of the Enron Bankruptcy" immediately below.

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. Assuming Bonneville's estimate of its refund exposure is correct, Bonneville's aggregate refund exposure would still be less than the amount owed to Bonneville by the Cal-ISO and Cal-PX.

*Effect on Bonneville of the Enron Bankruptcy*

On December 2, 2001, Enron Corp. and a number of its subsidiaries, including Enron Power Marketing Incorporated ("EPMI"), filed for bankruptcy protection under federal bankruptcy laws. At the time, EPMI was Bonneville's second largest electric power trading counterparty and Bonneville and EPMI had between them about one hundred separate transactions for forward sales and purchases of electric power. The parent, Enron Corp., guaranteed performance of all of Bonneville's power contracts with EPMI.

At the time of the bankruptcy filing, the aggregate amount of forward power transactions between Bonneville and EPMI exceeded 400 megawatts annually on average over the five years ending September 30, 2006. Under certain of the transactions, Bonneville agreed to sell power to EPMI and under other transactions, Bonneville agreed to purchase power from EPMI.

On March 20, 2003 the Enron Bankruptcy Court, the U.S. District Court for the Southern District of New York, approved in advance a proposed settlement of all claims relating to all power sales and purchase agreements between Bonneville and Enron. On April 25, 2003, Bonneville and Enron entered into an agreement to settle all claims between them relating to all power sales and purchase agreements between Bonneville and Enron. Under the settlement, Bonneville has agreed to cause to be paid to Enron a single lump sum payment of approximately $99 million, which reflects a discount in Bonneville's favor in the mark-to-market value of the remaining terms of the power transactions. The settlement agreement further provides that all of the claims and obligations of the parties with respect to the foregoing transactions are extinguished.

The lump sum payment to Enron was provided by the United States Treasury from the Judgment Fund on June 12, 2003. The Judgment Fund is a continuing, indefinite appropriation by Congress for the payment of certain claims and settlements involving the United States and certain of its agencies and instrumentalities. Bonneville is obligated to reimburse the United States Treasury for such payments and the reimbursement terms with the United States Treasury provide that Bonneville will make full repayment, together with interest, by the end of December 2006. This repayment period coincides roughly with the original final payment term of the related Enron power transactions.

The anticipated schedule of Bonneville's reimbursement payments to the United States Treasury are substantially less than the net payments Bonneville would have otherwise made to Enron had the power transactions continued to their original expiration dates. In addition, Bonneville estimates that it has a surplus of firm power through fiscal year 2006. Thus, Bonneville believes that the extinguishment of Enron's obligation to sell power to Bonneville will not have an adverse effect on Bonneville's ability to meet its contracted load obligations through fiscal year 2006.

Portland General Electric Company ("Portland General"), which is a Regional IOU as described herein and a contract party with Bonneville in several transactions, is a wholly owned subsidiary of Enron Corp. Portland General has not filed for bankruptcy protection. While Portland General has indicated that it has taken steps, with the consent of the bankruptcy court, to insulate itself and its assets from the Enron bankruptcy, Bonneville cannot provide any assurance whether such steps will in fact protect Portland General in the bankruptcy proceeding. As part of the bankruptcy proceeding Enron Corp. has solicited proposals for the purchase of Portland General. Bonneville continues to monitor Portland General's creditworthiness.

### 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.

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.

As required by law, Bonneville's power sales contracts with Regional utilities also include provisions that enable Bonneville, after giving notice, to allocate Federal System power, in accordance with statutory provisions, among its customers if Bonneville determines that it will have insufficient power, on a planning basis, to meet its firm load obligation. Bonneville does not anticipate experiencing a shortage of firm power that would require an allocation pursuant to these provisions. Bonneville's Subscription Strategy defines Bonneville's power-marketing program for the next five to ten years and seeks to extend the benefits of low-cost Federal System power widely throughout the Region. Among other things, the Subscription Strategy is intended to assure that Bonneville meets its statutory load obligations in the Region and avoids a resource planning insufficiency that would lead Bonneville to propose an allocation of Federal System power among its Regional customers. See "— Power Marketing in the Period After Fiscal Year 2001."

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.

Federal System Load/Resource Balance. 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.

Bonneville had estimated that its loads for the five years beginning October 1, 2001 (pre-existing obligations during such period plus anticipated Subscription loads) could exceed Federal System generation resources. Bonneville made power purchases in the market to address a portion of this potential shortfall, however, prices soared in the highly volatile deregulated wholesale power market. At the higher prices, Bonneville could not meet all obligations and maintain the initial base rate levels proposed in the Subscription process. To address the volatility of the wholesale power market, Bonneville negotiated amendments to certain Subscription contracts and proposed related rates, which incorporate: 1) cost recovery measures tied to the wholesale market price for power purchased by Bonneville to meet Subscription loads; and 2) reductions in Bonneville's power sales obligations through a combination of contracted load reductions and energy conservation measures. There are a number of variables that will affect the exact amount of load Bonneville will be required to serve during the five years beginning October 1, 2001. Customers have limited contract rights to withdraw from the Subscription contracts. See "— Power Marketing in the Period After Fiscal Year 2001." In addition, the contracted load reductions have various terms, but in no case do they extend past the end of fiscal year 2006. Thereafter, it is uncertain how much of that load will revert back to Bonneville. Among other things, the price of alternative power, load growth, and aluminum prices could affect Bonneville's power sales obligations, particularly in the later portion of the five-year rate period.

Bonneville's Authority to Add Resources. In order to meet the foregoing power sales obligations, Bonneville may have to obtain electric power from sources other than the Federal System hydroelectric projects, existing contract purchases and projects, such as the Columbia Generating Station, the capability of which Bonneville has previously acquired. 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 Electric Power and Conservation Planning Council (the "Council"). The governors of the states of Washington, Oregon, Montana and Idaho each appoint two members to the Council. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations.

Bonneville's Resource Strategies. Increased competition, deregulation in the electric power market and loss of hydropower flexibility due to ESA constraints have major implications for Bonneville's resource acquisition strategy. Given long-term load placement uncertainty, 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 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 revenue requirements. In dry years, Bonneville's revenue requirement would increase as it would be forced to spend a significant amount of money for short-term purchases to meet loads. In wet years, purchase requirements can be significantly reduced as Bonneville will meet more of its load with non-firm hydroelectric power. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation.

Bonneville's short-term purchase resource strategy is complemented by two other opportunities. First, Bonneville is adding environmentally preferred, so-called "green power" resources. The bulk of these additional purchases is likely to be from wind projects because of their relatively low cost and the expectation that the new wind projects can become operational within 12-18 months of a decision to proceed. While it is possible that Bonneville could acquire up to about 1000 megawatts of wind resources, the amount of wind energy resources that Bonneville ultimately purchases is uncertain and will depend on 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 green power resources, Bonneville has agreed to acquire 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 has contracted to purchase 49.9 megawatts from a geothermal project under construction in northern California and is considering additional purchases from renewable energy resources. Second, Bonneville will encourage electric power conservation measures by providing a 0.5 mills per kilowatt hour rate discount to its customers that implement conservation measures and/or renewable resource projects. The discounts should result in about $40 million per year (during the fiscal year 2002-2006 rate period) being spent on conservation and renewable resource initiatives by customers. In addition, Bonneville is purchasing about 100 average megawatts of conservation savings through fiscal year 2006 as part of its 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 has led Bonneville to make Augmentation Purchases. Consistent with the foregoing resource strategy, Bonneville has relied primarily on and will rely 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." While Bonneville believes that existing Augmentation Purchases and other actions to date will be sufficient to meet it is loads through fiscal year 2006, it is possible that it may have to make additional power purchases if loads are substantially higher than expected or if the amount of power provided by Federal System generating resources or existing power purchases declines unexpectedly.

*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 "purchases 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 then offers 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 changes hands — Bonneville makes 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. See "— Power Marketing in the Period After Fiscal Year 2001."

*Fish and Wildlife*

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 $419 million in fiscal year 2002. In addition, Bonneville estimates that it had about $12 million in Foregone Power

Revenues. The total of the preceding costs is within the range of such costs provided under the 1998 Guidance, as described in "— 1998 Guidance Regarding Fish and Wildlife Costs," and within the range assumed in the 2002 Final Power Rate Proposal.

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 2002 was about $430 million.

2000 Biological Opinion. In December 2000, NOAA Fisheries promulgated a new biological opinion ("2000 Biological Opinion") that superseded all previous opinions issued by it concerning the Federal System hydroelectric dams. The 2000 Biological Opinion has been 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 includes a number of measures that will affect Federal System operations and dam configurations in order to improve anadromous fish passage survival through the hydro system. In addition, the 2000 Biological Opinion calls for other measures from increased spill and additional flow requirements to extensive Columbia River Basin-wide habitat protections and enhancement efforts and fish hatchery reforms.

Included among the 13 biological opinion alternatives around which Bonneville developed its 2002 Final Power Rate Proposal 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. The 2000 Biological Opinion does not recommend implementation of dam breaching. However, NOAA Fisheries indicates that if measurable improvements in survival of listed fish are not seen, it may reinitiate formal consultations under the ESA with Bonneville, the Corps and the Bureau and recommend that they pursue authority to breach the four dams. In the opinion of the General Counsel to Bonneville, Congress would be required to enact legislation authorizing breaching of the dams.

The 2000 Biological Opinion sets forth a series of checkpoints to test the efficacy of programs identified therein to aid listed fish species. The 2000 Biological Opinion anticipates full implementation by 2010. In calendar years 2003, 2005 and 2008, NOAA Fisheries is expected to issue reports documenting whether the reasonable and prudent alternative measures identified in or to be developed under the 2000 Biological Opinion are on track or meet expectations. The first such report, which is to be completed in the fall of 2003, is expected to evaluate overall implementation of the reasonable and prudent alternative measures. The reports in year 2005 and year 2008 are expected to evaluate whether the measures are (a) failing, (b) acceptable, or (c) between failing and acceptable, with respect to (i) whether rolling one- and five-year plans for program implementation are on track, (ii) whether hydro performance (measures to improve fish passage past dams) and offsite mitigation (improvement of hatcheries, habitat and fish harvest) measures are on track, and (iii) whether the population status of listed species is on track. Under the 2000 Biological Opinion, NOAA Fisheries indicates that the 2008 checkpoint in particular is expected to focus on performance more than under the earlier checkpoints.

The 2000 Biological Opinion provides that if NOAA Fisheries concludes that there is a failure in these respects it will recommend whether to continue with the reasonable and prudent alternatives described in the 2000 Biological Opinion, revise them and/or recommend that the dam operators seek new legal authority from Congress. The new authority to be sought could include authority to breach dams, among other authorities. If such authority were not forthcoming, NOAA Fisheries indicates that it would then seek to reinitiate consultation pursuant to the ESA with the Corps and the Bureau and Bonneville over their hydroelectric project operations and recommend a new reasonable and prudent alternative for avoiding jeopardy to listed species.

A number of interests have 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 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. The court's order gives NOAA Fisheries a year to reconsider the biological opinion. To address the court's concerns, it is possible that a revised biological opinion may increase the forms and extent of mitigation measures beyond those required in the 2000 Biological Opinion as reviewed by the court. If NOAA Fisheries were to include additional or expanded measures in a new or amended biological opinion it is possible that substantial additional costs could be borne by Bonneville. 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 and $38.4 million in fiscal years 2001 and 2002, respectively. Bonneville currently projects that the recoupments will be about $82 million in fiscal year 2003, but the actual amount will depend to a great degree on actual hydroelectric generation results and market prices for electric energy through the remainder of the fiscal year. 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.

In addition to agreeing to a protocol for the foregoing, annually realized 4(h)(10)(C) recoupments, the same federal agencies also agreed in 1996 to establish a "Contingency Fund" to offset extraordinary revenue impacts from operations were there to occur certain adverse court rulings relating to biological opinions, specified poor water conditions and costs resulting from natural disasters or fishery emergencies. The source of the Contingency Fund is amounts Bonneville had theretofore expended for the non-power portion of fish and wildlife costs but had not recouped under section 4(h)(10)(C) against its payments to the United States Treasury. In 1997, Bonneville certified that there were approximately $325 million in costs for past mitigation that had not been recouped against its payments to the United States Treasury. Bonneville obtained access to the Contingency Fund for the first time at the end of fiscal year 2001 in view of the poor water conditions that year, and applied about $247 million from the Contingency Fund to reduce its fiscal year 2001 payments to the United States Treasury. The conditions governing access to the Contingency Fund were not met in fiscal year 2002, leaving an unused balance of about $78 million in the Contingency Fund. Bonneville is currently forecasting low water conditions in fiscal year 2003 and believes that it will obtain access to the Contingency Fund this fiscal year. Nonetheless, it remains uncertain whether the criteria for access to the Contingency Fund will be met this fiscal year.

1998 Guidance Regarding Fish Costs. In September 1998, the Clinton Administration announced Fish and Wildlife Funding Principles ("1998 Guidance"). The 1998 Guidance permits Bonneville to continue to receive the previously agreed to annual 4(h)(10)(C) recoupments. The 1998 Guidance also provides that Bonneville will set rates for the five-year rate period beginning fiscal year 2002 to achieve no lower than an 80% probability of meeting its federal repayment responsibilities in full over such period, assuming a range of fish and wildlife cost scenarios. Bonneville employed these criteria in developing the Final 2002 Power Rate Proposal. See "— Power Marketing in the Period After Fiscal Year 2001."

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 Rate Proposal. 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.

In response to financial developments over the past two years, Bonneville requested, and the Council has agreed, to a budget level of $139 million for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's 2002 Program. The Council is evaluating Bonneville's request that the fiscal year 2002 budget level remain in effect over the three remaining years of the five-year period beginning October 1, 2001. This level is approximately the same as was assumed in Bonneville's 2002 Final Power Rate Proposal.

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 has contracted to sell all of its 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, including the District. With the exception of eight contracts, which have terms of five years, 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 contracts require that customers make monthly payments based on expected costs of operating the Federal System, which payments are subject to retroactive annual adjustment to reflect actual costs. The Slice customers have the right to an outside audit of such annual "true up" adjustments. Certain Slice customers requested such an audit of the fiscal year 2002 "true up" adjustment, and retained an accounting firm that is now completing the audit and preparing a final report. Under the Slice contracts, Bonneville and the Slice customers will have 60 days to resolve any outstanding issues after the final report is concluded. In a related action, in the spring of 2003, several Slice customers filed "placeholder" litigation requesting review of Bonneville's accounting with regard to the Slice of the System product charges for fiscal year 2002. See "BONNEVILLE LITIGATION – Benton County PUD, et al. v. Bonneville Power Administration."

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 direct sales of 1000 average megawatts of firm power to the Regional IOUs at Bonneville's Residential Load Rate ("RL Rate"). The RL Rate is proposed to be at a level similar to Bonneville's lowest available requirements service rate, the PF Rate. In addition, Bonneville originally agreed to provide Regional IOUs with cash payments for the Exchange Value of 900 average megawatts of firm power. In general, the Exchange Value is based on 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. Bonneville expects that its aggregate payments to Regional IOUs for Exchange Value will amount to about $148 million per year on average over the five-year rate period. In fiscal year 2002, this amount was $144 million.

Through subsequent contract amendments with two Regional IOUs, Bonneville obtained an aggregate reduction of about 620 average megawatts in the amount of firm power sales Bonneville was to provide throughout the five-year rate period. To obtain these load reductions, Bonneville agreed to pay the two Regional IOUs about $240 million per year in aggregate. The two Regional IOUs also agreed to provide Bonneville with a discount to the foregoing payments if there is a settlement of certain litigation filed by Preference Customers challenging Bonneville's authority to enter into the Residential Exchange Settlement Agreements. See "BONNEVILLE LITIGATION — Residential Exchange Settlement Litigation." These payments, whether discounted or not, are recovered under the LB-CRAC in the 2002 Final Power Rate Proposal.

In addition, through the exercise by three other Regional IOUs of conversion rights in their Residential Exchange Settlement Agreements, Bonneville subsequently obtained about 125 average megawatts in additional load reductions throughout the five-year rate period. Under these conversions, Bonneville's power sales obligations converted into obligations to provide cash payments of about $10 million per year in aggregate throughout the five-year rate period. As a consequence of the foregoing actions, Bonneville's Subscription power sales obligation to Regional IOUs is now limited to a single power sales agreement with one Regional IOU. The amount of power Bonneville provided under this agreement was about 225 average megawatts in fiscal year 2002, and it increases to about 260 average megawatts in fiscal year 2006.

The foregoing payments to and by Bonneville under the Residential Exchange Settlement Agreements are or could be affected by the application of at least one of the three intra-rate period rate level adjustments included in the 2002 Final Power Rate Proposal. For example, the 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. Under certain contract provisions, the payments by Bonneville under the load reduction amendments are to be reduced in the event Bonneville employs a rate level adjustment under the SN-CRAC. In addition, since the Exchange Value is subject to certain changes by reference to the RL Rate, Bonneville's payments for the Exchange Value may be reduced if the RL Rate level is increased due to the triggering of the SN-CRAC.

For the five-year period after fiscal year 2006, Bonneville expects to meet its Residential Exchange settlement obligations in full through the actual provision of about 2200 average megawatts of electric power to the Regional IOUs. Nonetheless, Bonneville negotiated default provisions for the payment of monetary benefits in lieu of power to the extent that Bonneville becomes unable to provide the full 2200 average megawatts of power in such period. Bonneville must decide by October 1, 2005 how much power it will provide to the Regional IOUs under the Residential Exchange Settlement Agreements after fiscal year 2006.

DSI Loads. 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 power marketing 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. Under these DSI power sales contracts, as amended, the DSIs may curtail purchases but retain the take-or-pay requirements. If a DSI gives Bonneville advance notice that the DSI is unable or unwilling to take its power obligation to operate its facilities, Bonneville remarkets the power and applies the proceeds to offset the related DSI's payment obligation to Bonneville. In the event that re-marketing proceeds are less than the amounts owed Bonneville under the DSI contract, the DSI remains obligated to pay Bonneville the differential. In the event that re-marketing proceeds exceed the amounts due to Bonneville by the DSI, Bonneville retains the excess proceeds as well.

Bonneville is currently selling almost no power to DSIs, either because Bonneville agreed to buy back some of its sales obligations and/or to suspend some of the DSI purchase obligations, or because the DSI has curtailed its operations. In addition, two of the aluminum company DSIs have filed for bankruptcy protection. See "BONNEVILLE LITIGATION — Kaiser Aluminum Bankruptcy" and "BONNEVILLE LITIGATION — Longview Aluminum Bankruptcy."

In view of continued low prices for aluminum relative to the costs of production, and in particular the price of electric power under the DSI contracts, it is possible that other aluminum company DSIs may seek protection under the bankruptcy laws and reject their power contracts with Bonneville. Alternatively, such DSIs may fail to perform their take-or-pay purchase obligations entitling Bonneville to claims for breach of contract. In the event that Bonneville's sales prices under such contracts are higher than market prices it is possible that Bonneville would be left with unsecured claims for accrued accounts receivable and, roughly, the amount of power contracted to be sold times the positive difference between the contract prices minus applicable market prices. Under Bonneville's current forecasts of aluminum prices, Bonneville does not expect that aluminum company DSIs have an economic incentive to perform their purchase obligations in any material amount through the term of the contracts. While these possible future events could expose Bonneville to lost mark-to-market value (depending on volatile power prices) and certain other costs, Bonneville's expectation is that aluminum company DSI loads will remain at very low levels through fiscal year 2006. If contracted loads, especially those of DSIs, drop from current contract levels (after taking into account load reduction agreements), Bonneville could have a firm energy surplus in fiscal years 2004-2006.

Subscription Strategy Contracts Opt-Out Provisions. 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 during the next five to ten years remains somewhat uncertain because 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 proposed base power rates because they under-recover Bonneville's costs and Bonneville publishes a record of decision that adopts higher 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. Bonneville awaits a final order from FERC approving the 2002 Final Power Rate Proposal.

Risk Management. Bonneville believes that its ability to recover power costs 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 cost of power Bonneville purchases to meet commitments that exceed Federal System resources and 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.

Subscription Power Rate Proposal. On June 29, 2001, Bonneville filed its 2002 Final Power Rate Proposal with FERC, proposing power rates for the five years beginning October 1, 2001. On September 28, 2001 FERC granted interim approval of such rates pending final review. Bonneville awaits a final order by FERC approving the proposal. The rate proposal includes proposed base rates applicable to the varying types of Subscription agreements and certain intra-rate period adjustments that will increase or decrease power rate levels depending on certain conditions. The base rate levels proposed by Bonneville are between approximately 1.9 cents per kilowatt hour and 2.30 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 rate proposal also includes 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 2002 Final Power Rate Proposal is comprised of the initial rate filing with FERC proposing the "base rates" and a subsequent supplementary rate filing with FERC that amends the initial proposal by proposing the LB-CRAC, FB-CRAC and SN-CRAC.

The proposed 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 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 cost 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 proposed FB-CRAC is designed to restore, on a forecasted basis, Bonneville's financial reserves to fiscal year-end reserve levels ("Reserve Targets") of $300 million in fiscal years 2002 and 2003 and $500 million in each of fiscal years 2004-2006. 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. A rate increase under the FB-CRAC continues through the end of the applicable fiscal year.

In fiscal years 2003-2006, the revenues to be derived under an FB-CRAC increase are capped at a maximum of between $90 million and $115 million per fiscal year, depending on the year.

The proposed 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. An SN-CRAC adjustment could alter certain parameters of an FB-CRAC adjustment, including the amount of revenue that can be collected, the duration of rate level adjustments, and the timing of collection of revenues, in each case under the FB-CRAC. Under the 2002 Final Power Rate Proposal, Bonneville determines the level of the SN-CRAC in a record of decision after a brief formal rate-setting process.

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 aggregate purchase obligations to a substantial degree. The remaining 300 megawatts of Subscription power sales under the Residential Exchange Settlement Agreements are subject to the LB-CRAC, FB-CRAC and the SN-CRAC.

For the first six months of the rate period, the LB-CRAC adjustment increased rate levels by 46% of the base rates for the rate period and, coincidentally, the rates for like service in the preceding rate period. For the second six months of the rate period, the LB-CRAC was set at about 39% of the base rates, and for the third six-month period (beginning October 1, 2002), the LB-CRAC was set at about 32% of base rates. Bonneville has notified its customers that the LB-CRAC for the six months beginning April 1, 2003, will be about 39% of base rates. Bonneville expects that the LB-CRAC adjustments for the remainder of the rate period will be in roughly the same range as has been the case to date.

The FB-CRAC was not implemented for fiscal year 2002 rates; however, the FB-CRAC was triggered after the third quarter fiscal year 2002 year end forecast, thus commencing a one-year rate level increase beginning October 1, 2002. The FB-CRAC adjustment in effect for fiscal year 2003 is roughly 11% of base rates for those contracts to which the FB-CRAC applies. Bonneville expects that the FB-CRAC will trigger again for fiscal year 2004, although, under the terms of the FB-CRAC, such a determination will be made some time after the end of the third quarter of this fiscal year. In connection with its proposal for an SN-CRAC rate level adjustment, Bonneville expects that it will propose to adjust the financial conditions under which the FB-CRAC would trigger. Such changes would assure that the conditions for the proposed SN-CRAC rate level adjustment are not met unless the FB-CRAC conditions have been met.

Taking the cumulative effects of the base rates, the LB-CRAC and the FB-CRAC into account, average Subscription power rate levels for Block Sales and Requirements Products in each six month period to date were roughly: i) 2.9-3.3 cents per kilowatt hour in the first six months of the rate period, ii) 2.7-3.1 cents in the second six months of the rate period, and iii) 2.8-3.2 cents per kilowatt hour in the third six months of the period, in each case excluding transmission. Beginning April 1, 2003, the cumulative average Subscription power rate levels will be about 3.0-3.4 cents per kilowatt hour, excluding transmission.

On February 7, 2003, Bonneville issued a letter notifying its customers that the conditions triggering the SN-CRAC have been met and that Bonneville has initiated the formal rate procedures to possibly increase rate levels thereunder. In February 2003, Bonneville estimated that there would be approximately a 26 percent probability that it would meet in full its scheduled fiscal year 2003 payments to the United States Treasury.

On March 13, 2003, Bonneville published its initial proposal for the SN-CRAC rate level adjustment. The initial proposal called for a three-year variable SN-CRAC adjustment to be determined annually by reference to indicators of Bonneville's financial condition.

The initial proposal for the SN-CRAC rate level adjustment was designed to recover an expected value of about $340 million to $370 million for each of the three fiscal years in which it is proposed to be in effect. Bonneville estimated that the SN-CRAC rate level adjustment under the initial proposal would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels by an average of about 15.7 percent over fiscal year 2003 levels.

In anticipation of issuing a final record of decision supporting Bonneville's final proposal for the SN-CRAC rate level adjustment, Bonneville released a draft record of decision on June 16, 2003. The draft record of decision indicates Bonneville's expected approach to the final proposal for the SN-CRAC rate level adjustment. In view of improved water conditions, better than expected revenues from surplus sales, and cost management actions, Bonneville now anticipates that the final SN-CRAC rate level increase for fiscal years 2004-2006 that is less than the SN-CRAC rate level adjustment Bonneville initially proposed. Bonneville now anticipates that it will propose an SN-CRAC rate level adjustment that would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels in fiscal years 2004-2006 by an average of about 5 percent over fiscal year 2003 levels. Bonneville expects to issue the final record of decision and the final SN-CRAC rate level adjustment rate proposal at the end of June or early July 2003.

While the final SN-CRAC adjustment proposed by Bonneville will be influenced by various projections and forecasts, the draft record of decision indicates that the SN-CRAC would be implemented as a variable contingent mechanism, where the calculation of the actual rate level adjustment for a fiscal year will be made about two months before the beginning of such fiscal year. The adjustment would be based on then current forecasts of the Power Business Line net revenues for the fiscal year preceding the fiscal year in which the rate level adjustment is to be in effect.

Assuming an SN-CRAC adjustment such as Bonneville put forth in the draft record of decision and expected rate level adjustments in fiscal year 2004 under the FB-CRAC and LB-CRAC, Bonneville's average power rates would 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 herein, 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.

In proposing a rate level increase under the SN-CRAC, Bonneville expects, among other things, that it will use lower forecasts of price levels for discretionary surplus power sales and lower forecasts of revenues from such sales than Bonneville used in the final stages of developing the 2002 Final Power Rate Proposal.

The procedures for implementing the SN-CRAC require that Bonneville develop an initial proposed adjustment, conduct evidentiary hearings before a hearings officer, prepare an administrative record setting forth a final proposal and the rationale therefor, and submitting the record and final proposal to FERC for review. Bonneville expects to submit the final proposal and record of decision to FERC in late June or early July 2003.

Rate Proposal 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. With the exception of most months through the rest of fiscal year 2003, Bonneville does not expect to have substantial firm power to market during the remainder of the five year rate period because of Subscription sales. 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 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 section 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 section 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 section 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 a section 211/212 order for transmission service. 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 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 section 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.

In 1997, the State of Montana, in which a small number of cooperatively owned Net Billing Participants conduct business, enacted legislation providing for competitive retail markets. The legislation enables such cooperatives voluntarily to permit retail choice in their service territories. Under the legislation, if a Montana Net Billing Participant were to provide access over its distribution facilities to competitors, it would nonetheless be entitled to collect "transition costs" on a non-avoidable basis, subject to the obligation to mitigate transition costs. Transition costs are defined to include "existing commitments or obligations incurred before May 2, 1997." Under the Montana legislation, the ability of a Participant to collect transition charges is not limited in duration. Also, the Montana Net Billing Participants retain discretion to determine the extent and nature of their transition costs. To date, only one Montana electric power cooperative has chosen to permit full retail choice for all customers in its service territory. This cooperative has not experienced load loss, apparently due to the favorable rates it is able to offer its customers.

In 1999, the State of Oregon enacted a retail competition law. The Oregon law specifically preserves the ability of Net Billing Participants located in Oregon to charge rates for use of distribution facilities to recover their obligations under their Net Billing Agreements. The implementation provisions of open access contained in this law were delayed with the passage of a subsequent law in 2001.

Most of the Net Billing Participants serve retail loads in Washington. In 1997, the state legislature considered but did not enact proposals to implement competitive retail power markets. No similar bills have since been introduced in the legislature and Bonneville believes it is very unlikely that a restructuring bill will be introduced in the near future. While Bonneville believes that retail competition legislation in Washington, if enacted, would preserve the Participants' obligations under the Net Billing Agreements, Bonneville cannot predict whether the state will enact retail competition or the terms thereof should such legislation be enacted.

Several Participants serve loads in Idaho. The Idaho State legislature has not introduced legislation that would establish retail competition.

**TRANSMISSION BUSINESS LINE**

**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. 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 ("MW"), 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 System transmission facilities are 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 the Bonneville 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 transmission system, including Bonneville's Power Business Line.

Bonneville has not added significant capacity to its transmission system since 1987. Bonneville is currently studying additional possible transmission investments to ease congestion, integrate new generation and provide a reliability margin on the transmission system. Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $425 million a year over the four fiscal years commencing October 1, 2002. The transmission system is operated at or near capacity and congestion is developing in some areas of the system. Load growth on the system has been about 1.8% a year and transmission use has grown about 2% a year. In addition, Bonneville expects to interconnect between 2000 and 5000 megawatts of proposed and new generation to the transmission system over the next four years. A number of issues will have to be resolved prior to Bonneville's committing to its transmission investment levels, including identifying sources of funding and determining which investments should be made by Bonneville. With regard to the financing of the foregoing projects, Bonneville will 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. With regard to congestion and reliability investments, Bonneville expects to use its United States Treasury borrowing authority, although it is possible that Bonneville may use other sources of financing.

**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 section 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 2002 transmission and ancillary services rates were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. Such rates are effective through September 30, 2003. In January 2003, Bonneville published its initial transmission and ancillary services rate proposal for fiscal years 2004-2005. Under the initial proposal Bonneville would increase such rates by 1.5 per cent. Bonneville expects to issue a final proposal and submit it to FERC for review in the spring of 2003. The final proposal could differ from the initial proposal.

**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. The order, "Order 2000," encouraged each jurisdictional utility (Bonneville is not a jurisdictional utility) to file a proposal for an RTO that would be operational by December 15, 2001.

In March 2000, Bonneville, six Pacific Northwest IOUs and two Nevada utilities (collectively, the "Filing Utilities") agreed to a set of RTO Principles and a general description of an RTO Form and Structure, and proposed to work to submit an RTO proposal to FERC. The RTO Principles provide, among other things, that "[w]ith respect to the Bonneville Power Administration, the RTO shall be designed so as (a) not to increase the risk to the United States Treasury or to third party bondholders and (b) to avoid financial restructuring of low-cost Bonneville debt."

In October 2000, the Filing Utilities filed with FERC a response to Order 2000 proposing the formation of a nonprofit RTO (to be named RTO West) for a region composed of Washington, Oregon, Idaho, Utah, Nevada, Montana and western Wyoming. Under the evolving RTO West proposal, Bonneville would retain ownership of all of the Federal System transmission assets, but would transfer planning and operational control over most of such facilities to RTO West and establish RTO West as the exclusive provider of transmission service over such facilities. Under the current draft operating agreement, Bonneville would retain the responsibility for maintaining the Federal System transmission assets. Investments to expand the Federal transmission system could be accomplished by Bonneville or third parties, with RTO West allocating the expansion costs to transmission owners who benefit from the expansion, including Bonneville. Until December 2011 or such other transition period approved by FERC, costs for the use of Bonneville's transmission facilities would be recovered through Bonneville's own "company rates." The draft operating agreement also provides that Bonneville would continue to set its costs and billing determinants, which would be applied by RTO West to derive company rates that recover Bonneville's costs from its own loads. In the opinion of the General Counsel to Bonneville, assuming the entry by Bonneville into the draft operating agreement, the draft operating agreement would be consistent with Bonneville's obligation to recover its costs, and would not interfere with Bonneville's authority to recover "stranded costs," which are defined in the draft operating agreement to include power function costs. See "— POWER BUSINESS LINE — Certain Statutes and other

Matters Affecting Bonneville's Power Business Line — Recovery of Stranded Power Function Costs." Under the draft operating agreement, no directive of RTO West may require Bonneville to violate its obligations under applicable statutes or regulations.

In April 2001, FERC acknowledged the need to provide assurances and protections to Bonneville with respect to its ability to continue to meet its statutory, treaty, contractual and other responsibilities. FERC also clarified that its jurisdiction over Bonneville is limited with regard to RTO formation, and that Bonneville's authority to participate in RTO West is not subject to review by FERC. The General Counsel to DOE issued an opinion in May 1999, that Bonneville's participation in or affiliation with a regional transmission entity would not require federal legislation, provided the terms of such participation do not interfere with Bonneville's ability to perform its statutory duties.

FERC also found that while RTO West will have the exclusive authority to make filings under section 205 of the Federal Power Act (applicable to jurisdictional utilities) that apply to rates, terms and conditions of RTO West Tariff service, it acknowledged that Bonneville is not a Federal Power Act jurisdictional utility and clarified that Bonneville's rates are established by the Administrator, and approved or disapproved by FERC. FERC also does not have the power to modify Bonneville's rates under the current statutes applicable to Bonneville.

FERC also rejected an RTO West proposal limiting the liability of the RTO West participants (including Bonneville) through a "no fault" liability structure for electric system property damage, liability limitations for tariff service interruptions, and indemnity provisions for bodily injury claims. In July 2001, FERC reversed itself in part and agreed to accept a proposal to allocate risk among the transmission owners and RTO West. FERC did not change its decision not to use the tariff to limit the liability of RTO West and transmission owners for damages to transmission users from interruptions in tariff service and bodily injury claims. In the opinion of the General Counsel to Bonneville, assuming the entry by Bonneville into the draft operating agreement, the Federal Torts Claims Act, which limits the grounds and manner in which the United States may be sued for actions sounding in tort, would continue to apply to actions taken by Bonneville in connection with RTO West. Nonetheless, liability for actions taken by RTO West could subject RTO West to liability and such costs could be allocated to Bonneville as a charge in applicable rates and tariffs.

In July 2002, FERC issued a new Notice of Proposed Rulemaking proposing to modify the Order 888 *pro forma* tariff for an interim period, and proposing a new standardized network access transmission service for independent transmission companies or RTOs and a new standardized market design for wholesale power participants (SMD NOPR). In September 2002, FERC approved a majority of the Phase 2 filing, including the company rate concept, an 8-year transition period, voluntary conversion of existing transmission contracts to RTO West Tariff service, and a modified congestion management proposal, FERC rejected the proposal that the proposed operating agreement provisions would govern in the event of a conflict with the RTO West Tariff. FERC directed the Filing Utilities to submit a memorandum of understanding providing for cooperation between the proposed western RTOs for resolving interregional issues. FERC also urged the Filing Utilities, in collaboration with stakeholders, to strengthen the oversight of the RTO West market monitoring unit regarding market mitigation measures to prevent the exercise of market power due to market design flaws or unusual market conditions. The RTO West market monitoring unit would report directly to FERC.

The Filing Utilities continue to work on the issues raised by FERC in its September 2003 order, the Filing Utilities' Phase 3 proposal, and the remaining complex issues that must be resolved to obtain agreement of the parties and obtain FERC approval of the proposal. Bonneville's current expectations are that RTO West would not begin operating transmission assets until calendar year 2006 or 2007.

In February 2003, two customer groups representing many of Bonneville's Preference Customers filed a petition for review in the United States Court of Appeals for the District of Columbia. This petition for review requests the court to modify or set aside prior FERC rulings relating to the RTO West proposal. While no specific grounds for the review are identified in the petition, Bonneville expects that petitioners will reassert their concerns that FERC has improperly refused to assess the costs and benefits of the RTO West proposal and that Bonneville lacks authority to join RTO West.

## 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 and — 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 three such sites. One of these sites is a Bonneville-operated facility awaiting determination by the EPA, but two are non-Bonneville sites 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 be between $1 million and $2 million total 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 regulation comparable to regulation 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, and requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates. None of these bills or proposals were enacted into law.

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 obligation with respect to the Net Billed Bonds. However, Bonneville believes that any major electric industry restructuring affecting its obligations with respect to the Net Billed 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 Net Billed Bonds. Bonneville would oppose any proposal that would have an adverse impact on the tax-exempt status or the credit structure of the Net Billed 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.

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, 2002, Bonneville had repaid $4.5 billion of principal of the Federal System investment and has $4.5 billion principal amount outstanding.

### 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 increases 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 the Administrator's authorities under the Northwest Power Act. The law also restricts the amount of permanent borrowing authority Bonneville may use in fiscal year 2003 to $531 million. Bonneville believes that this limitation will have no material effect on Bonneville's finances in fiscal year 2003.

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.77 billion of bonds were outstanding as of September 30, 2002. 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.

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, 2002, the interest rates on the outstanding bonds ranged from 3.05% to 8.55% with a weighted average interest rate of approximately 6.01%. 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: 45 years for transmission facilities and Corps and Bureau capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. All bonds with original maturities greater than 15 years may be called early, except for three bonds totaling $258.8 million.

### Debt Optimization Proposal

In the spring of 2000, Bonneville presented a "Debt Optimization Proposal" to Energy Northwest. The proposal involves the extension of the final maturity of certain bonds for the Columbia Generating Station the debt service of which Bonneville secures under net billing agreements as described herein. In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it incorporated an increase in the average life of Projects 1 and 3 Net Billed Bonds 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.

**Order in Which Bonneville's Costs Are Met**

Bonneville's operating revenues include net billing credits provided by Bonneville, under certain Net Billing Agreements, to certain Participants in return for payments by such customers to Energy Northwest to meet certain costs of its Columbia Generating Station, Project 1 and Project 3, and to the City of Eugene, Oregon, Water and Electric Board ("EWEB") to meet certain costs of the Trojan Nuclear Project, a terminated nuclear project owned in part by EWEB. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Trojan Nuclear Project, Project 1, the Columbia Generating Station and Project 3, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. These credits reduce the amount of revenues Bonneville has available to pay other obligations, including payments with respect to the 2003 Bonds.

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 2002 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.056 billion in fiscal year 2003, approximately $266 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury and certain appropriated repayment obligations. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Proposal through the use of cash flows derived from reduced Net Billed Project debt service in such fiscal year. 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.

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 payments relating to the 2003 Bonds 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 make payments to the United States Treasury only from net proceeds; all cash payments of Bonneville, including cash payments relating to the 2003 Bonds and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury for the costs described in items (i) to (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 can 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 would pay 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.

In November 1996, Bonneville and the Bureau agreed to a five-year direct funding agreement, beginning in fiscal year 1998, for roughly $40 million in annual operations and maintenance expense at the Bureau's Federal System facilities. In December 1997, Bonneville and the Corps entered into a ten-year agreement for direct funding that is expected to result in roughly $100 million per year in direct payments by Bonneville, beginning in fiscal year 1999. In September 2000, Bonneville and the Fish and Wildlife Service entered into a one-year agreement for direct funding of power related operations and maintenance costs of the Lower Snake River Compensation Plan Program ("Snake River Plan"), a fish and wildlife program funded in part by Bonneville. In January 2001, Bonneville and the Fish and Wildlife Service entered into a five-year agreement for direct funding of power related operations and maintenance costs of the Snake River Plan. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2002 were $51 million for the Bureau, $132 million for the Corps, and $15 million for the Fish and Wildlife Service.

Direct funding differs from historical practice under which (i) the Corps and the Department of Interior obtained specific appropriations from Congress for Federal System operations and maintenance, with relatively little influence from Bonneville as to the nature or amount of any such expense and (ii) Bonneville repaid the appropriations, with interest, at the end of the fiscal year for which the appropriations were made, which repayments were otherwise subject to deferral if Bonneville had inadequate amounts in the Bonneville Fund. Under Bonneville's statutory priority of payments, Bonneville's repayments of amounts appropriated to the Corps and the Department of Interior for Federal System operations and maintenance expense are made annually after the payment of Bonneville's non-federal payment obligations in the related fiscal year. As with Bonneville's other repayments to the Treasury, repayments of appropriated operations and maintenance expense would be subject to deferral if Bonneville were to have insufficient amounts in the Bonneville Fund to meet its non-federal payments.

Bonneville believes that, in contrast to historical 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.

### 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 is concerned that its decisions to manage and economically hedge 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, which includes Bonneville's third party debt service obligations with regard to the Net Billed Bonds. 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 fixed rate Net Billed 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 will be 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 2000 through 2002 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information was extracted from audited financial statements or accounting records supporting the audited financial statements. 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, 2002 are included as Appendix A-1 hereto and Bonneville's unaudited quarterly report for the six months ended March 31, 2003 is included as Appendix A-2 hereto.

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

| Fiscal year ending September 30, | 2002 | 2001 | 2000 |
|---|---|---|---|
| Operating Revenues: | | | |
| Sales of electric power — | | | |
| Sales within the Northwest Region — | | | |
| Publicly-owned utilities [1] | $ 1,797,496 | $ 939,362 | $ 934,270 |
| Aluminum industry | 58,454 | 420,694 | 363,454 |
| Investor-owned utilities | 377,789 | 700,836 | 649,449 |
| Other power sales | 1,293 | 972 | 38,578 |
| Sales outside the Northwest Region [2] | 638,261 | 1,084,077 | 652,221 |
| Total Sales of Electric Power | 2,873,293 | 3,145,940 | 2,637,972 |
| Transmission and other revenues [3] | 660,436 | 1,132,729 | 402,197 |
| Total Operating Revenues | 3,533,729 | 4,278,669 | 3,040,169 |
| Operating Expenses: | | | |
| Bonneville O&M [4] | 775,077 | 530,618 | 506,878 |
| Purchased Power | 1,286,867 | 2,291,961 | 624,882 |
| Corps, Bureau and Fish & Wildlife O&M [5] | 198,055 | 184,922 | 162,621 |
| Non-Federal entities O&M — net billed [6] | 167,026 | 208,839 | 193,085 |
| Non-Federal entities O&M — non-net billed [7] | 35,566 | 30,719 | 32,942 |
| Total Operation and Maintenance | 2,462,591 | 3,247,059 | 1,520,408 |
| Net billed debt service | 213,919 | 455,397 | 535,460 |
| Non-net billed debt service | 16,256 | 21,818 | 25,139 |
| Non-Federal Projects Debt Service [8] | 230,175 | 477,215 | 560,599 |
| Federal Projects Depreciation | 335,205 | 323,314 | 319,942 |
| Residential Exchange [9] | 143,983 | 68,082 | 63,593 |
| Total Operating Expenses | 3,171,954 | 4,115,670 | 2,464,542 |
| Net Operating Revenues | 361,775 | 162,999 | 575,627 |
| Interest Expense: | | | |
| Appropriated Funds | 352,551 | 317,213 | 315,826 |
| Long-term debt | 151,997 | 129,159 | 115,052 |
| Capitalization Adjustment [10] | (67,356) | (68,784) | (67,474) |
| Allowance for funds used during construction | (57,892) | (45,679) | (28,754) |
| Net Interest Expense | 352,300 | 331,909 | 334,650 |
| Cumulative Effect of SFAS 133 [11] | | (168,491) | |
| Net Revenues/(Expenses) | $ 9,475 | $ (337,401) | $ 240,977 |
| Total Sales — average megawatts (Net of Residential Exchange Program) | 11,225 | 10,302 | 11,361 |

(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 stream flows in the Columbia River Basin, which affect the amount of non-firm energy available for sale, and upon the costs of generating power with alternative fuels, which affect the price Bonneville can obtain for its exported non-firm energy and surplus firm power.
(3) Bonneville obtains revenues from the provision of transmission and other related services. 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.
(4) 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.

(5) Corps, Bureau and Fish & Wildlife operations and maintenance expenses include the costs for the Corps and Bureau generating facilities included in the Federal System as well as expenses incurred by the U.S. Fish & Wildlife Service in connection with the Federal System.
(6) The Non-Federal 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.
(7) The Non-Federal entities O&M – non-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 not net-billed.
(8) 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 City of Eugene Water and Electric Board's 30% ownership share of the Trojan Nuclear Project. These amounts also include payment by Bonneville with respect to several small generating and conservation projects.
(9) See "POWER BUSINESS LINE — Certain Statutes and Other Matters Affecting Bonneville's Power Business Line" and "— Residential Exchange Program."
(10) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing federal appropriations under legislation enacted in 1996.
(11) On October 1, 2000, the date of adoption by Bonneville of Financial Accounting Standards Board Statement of Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville recorded a cumulative-effect adjustment of $168 million loss to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted primarily of transactions known as bookouts that the FASB initially determined should be fair valued in net revenue (expense). While authoritative accounting guidance in this area continued to emerge during fiscal year 2001, Bonneville management elected to apply the most current guidance available related to SFAS 133, as amended.

**Management Discussion of Operating Results**

Bonneville had positive net revenues of $9.5 million in fiscal year 2002, an increase of approximately $347 million over fiscal year 2001 when Bonneville had negative net revenues 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 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 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 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 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. For a description of 4(h)(10)(C) credits and the Contingency Fund see "— Fish and Wildlife — Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

Total operating expenses in fiscal year 2002 were approximately $3.2 billion, a decrease of $944 million, or 22%, 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 $242 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 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.

For fiscal year 2001, Bonneville had negative net revenues of approximately $337 million, a substantial decline of approximately $578 million from net revenues in fiscal year 2000. Total operating revenues increased over fiscal year 2000 by approximately $1.2 billion, despite a very low water year, primarily due to a tripling in market prices for discretionary power sales from the previous year, and a ten-fold increase in fish credits under the Northwest Power Act, as described below. These extremely high market prices translated into an increase of $432 million, or 66%, in revenues from sales outside the Region. In addition, Bonneville remarketed power returned by certain aluminum company DSIs and the remarketing of this returned power increased revenues from the aluminum company DSIs by $57 million, or 16%, in fiscal year 2001. The higher prices for power increased sales revenues from Regional IOUs by $51 million, or 8%. Conversely, power sales revenues from non-aluminum company DSIs declined by approximately $38 million, or 97%, due to decreased power sales to these customers. The $731 million, or 182%, increase over fiscal year 2000 in revenues from transmission and other related services, is due to estimated Treasury repayment credits of $354 million under Section 4(h)(10)(C) of the Northwest Power Act and to Treasury repayment credits of $247 million from the Contingency Fund. Total operating expenses increased by approximately $1.6 billion in fiscal year 2001 over fiscal year 2000. This was in large part due to extremely high market prices for power in the Western markets. Purchased power expenses increased by $1.67 billion, or 267%, due to a 137% increase in the amount of power purchased by Bonneville in response to low water conditions as well as the aforementioned high market prices at which such purchases were made. In addition, Corps, Bureau and Fish and Wildlife Service operations and maintenance expenses increased by $22 million in fiscal year 2001 due to, among other factors, an increased maintenance program at the Corps designed to help increase the availability of generation units and an increase in the power purpose's responsibility for certain costs of Grand Coulee Dam. See "BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund" in this Official Statement. Non-Federal entities O & M – net-billed expenses increased by $16 million due to increased operating expenses related to the Columbia Generating Station. However, net-billed debt service decreased by $80 million, or 15%, due to refinancing and restructuring of a portion of the outstanding net-billed debt.

**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 7 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**
**(Actual Dollars in Thousands)**

| Fiscal Years ending September 30, | 2002 | 2001 | 2000 |
|---|---|---|---|
| Total Operating Revenues | $ 3,533,729 | $ 4,278,669 | $3,040,169 |
| Less: Operating Expense[(1)] | 2,408,520 | 3,130,219 | 1,421,380 |
| Net Funds Available for Non-Federal Project Debt Service | 1,125,209 | 1,148,450 | 1,618,789 |
| Less: Total Non-Federal Project Debt Service[(2)] | 230,175 | 477,215 | 560,599 |
| Revenue Available for Treasury | 895,034 | 671,235 | 1,058,190 |
| Amount Paid to Treasury: | | | |
| Corps and Bureau O&M[(3)] | 198,055 | 184,922 | 162,621 |
| Net Interest Expense[(4)] | 352,300 | 331,909 | 334,650 |
| Capitalization Adjustment[(5)] | 67,356 | 68,784 | 67,474 |
| Allowance for Funds Used During Construction[(4) (6)] | 15,061 | 12,479 | 8,578 |
| Amortization of Principal | 505,012 | 210,127 | 289,925 |
| Total Amount Allocated for Payment to Treasury[(7)] | 1,137,784 | 808,221 | 863,248 |
| Revenues Available for Other Purposes[(8)] | (242,750) | (136,986) | 194,942 |
| Non-Federal Project Debt Service Coverage Ratio[(9)] | 4.9 | 2.4 | 2.9 |
| Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[(10)] | 1.3 | 1.2 | 1.5 |

(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, including payments with respect to the 1994 Bonds. Non-net billed debt service amounted to $25.1 million, $21.8 million and $16.3 million for fiscal years 2000, 2001 and 2002, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps and Bureau for fiscal years 2000, 2001 and 2002, and to Fish & Wildlife Service for fiscal years 2001 and 2002. 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 2000, 2001 and 2002 were $732 million, $729 million and $1.056 billion, respectively. In fiscal years 2000, 2001 and 2002, respectively, direct payments to the Corps and Bureau for operations and maintenance were included in the amount of (i) $104 million, $117 million and $132 million for the Corps, and (ii) $46 million, $55 million and $51 million for the Bureau. In fiscal years 2001 and 2002, direct payments for Fish & Wildlife Service were $13 million and $15 million, 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 $670 million at the end of fiscal year 1999 and $188 million at the end of fiscal year 2002.

(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** [(1) (5)]
**(Actual Dollars in Thousands)**

| Fiscal years ending September 30, | 2002 | 2001 | 2000 |
|---|---|---|---|
| Operating Revenues from Publicly-Owned Utilities[(2)] | $ 1,797,496 | $ 939,362 | $ 934,270 |
| Net Billing Obligations: | | | |
| Net Billing Credits | 610,180 | 675,938 | 642,541 |
| Payments in Lieu of Net Billing[(3)] | (111,329) | 57,283 | 66,992 |
| Net Billing Obligations — Cash | 498,851 | 733,221 | 709,533 |
| Net Billing Expenditures: | | | |
| Net Billed Debt Service | 213,919 | 455,397 | 535,460 |
| Other Entities O&M — Net Billed | 167,026 | 208,839 | 193,085 |
| Increase/(Decrease) in Prepaid Expense | 117,906 | 68,985 | (19,012) [(4)] |
| Net Billing Expenditures — Accrual | $ 498,851 | $ 733,221 | $ 709,533 |

(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.
(3) Includes voluntary direct cash payments made to Energy Northwest by Bonneville when the Participants' obligations to Energy Northwest exceed the allowed net billing credits.
(4) Excludes $22.2 million of prepaid expenses not associated with the Net Billed Projects.
(5) While the Bonds are not serviced by net billing, this table is provided to illustrate the extent of Bonneville's net billing obligations.

## BONNEVILLE LITIGATION

### Kaiser Aluminum Bankruptcy

Kaiser Aluminum and Chemical, Incorporated ("Kaiser"), a subsidiary of Kaiser Aluminum Corporation, is an aluminum company DSI customer of Bonneville. On February 12, 2002, both Kaiser and its parent corporation Kaiser Aluminum Corporation filed for bankruptcy protection. Bonneville has a contract (the "Kaiser Contract") to sell Kaiser about 291 megawatts of electric power during the five-year period beginning October 1, 2001. Under an arrangement entered into after Kaiser and Bonneville executed the Kaiser Contract, Kaiser agreed to forgo most of such purchases, and Bonneville agreed to waive the obligation of Kaiser to make most of such purchases, through October 2003. Consequently, since October 1, 2001, Kaiser has been purchasing only about 30 megawatts of power under the Kaiser Contract. 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 could 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. The rate under which Kaiser is obligated to make such purchases is the Bonneville Industrial Firm Power (or "IP") Rate, which is currently about $34 per megawatt, subject to the various cost recovery rate adjustments described herein. The current IP Rate is above the current West Coast market prices for electric power. Due to these circumstances, 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.

**Benton County PUD et al. v. Bonneville Power Administration**

In April, 2003, several Bonneville preference customers that purchase their power under contracts termed Slice and Block products, filed a petition with the Ninth Circuit Court requesting review of certain undefined actions taken by Bonneville regarding the accounting for the Annual Slice True-up for Actual Costs and the Actual Slice Revenue Requirement under their contracts. Petitioners describe their filing as a "placeholder" action, and allege that Bonneville's issuance of the accounting is a final action under section 9(e)(5) of the Northwest Power Act. A conference with the Circuit mediator was held on May 19, 2003, and the case is stayed until August 31, 2003 for discussions between Bonneville and the petitioners.

**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 that are not yet in arrears 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 has asserted to Bonneville, and Bonneville disagrees, that the power sales contract entitles Longview to suspend its take-or-pay purchase obligation. 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. Bonneville is evaluating potential actions to obtain payment. While Bonneville is not optimistic that it will receive full value for these contract obligations, Bonneville has not yet determined whether to take an accounting charge reflecting unrecoverable revenues in this matter.

In February 2003, Longview Aluminum filed two petitions for review against Bonneville in the Ninth Circuit Court. The first petition is a challenge to an invoice from Bonneville's Power Business Line for approximately $16 million. The second petition, with approximately $450,000 at issue, concerns invoices from Bonneville's Transmission Business Line. No legal theory was given as a basis for either suit, and the petitions did not request any relief.

On March 4, 2003, Longview filed for bankruptcy protection under the federal bankruptcy laws. Bonneville will seek payment for amounts owed it by Longview in the bankruptcy proceeding.

**CPN Cascade, Inc., formerly d/b/a CE Newberry, Inc. v. Bonneville Power Administration**

In October 2002, CPN Cascade, Inc. filed a petition for review in the Ninth Circuit Court. The petition is styled as a precautionary petition for review to comply with the 90-day statute of limitations contained in the Northwest Power Act.

The subject of the petition is a 48-megawatt geothermal power project that CPN has yet to construct, and power from the project that CPN seeks to sell to Bonneville. Bonneville and CPN have an ongoing dispute over a settlement agreement related to the project and Bonneville's obligations to pay certain funds to CPN Cascade. In July 2002, Bonneville sent a letter to CPN stating that Bonneville believes its obligations under the agreement have been fulfilled or extinguished. CPN disagreed and filed the petition for review alleging that statements made by Bonneville in the July 2002 letter were arbitrary, capricious, an abuse of discretion, and violate the terms of the settlement agreement.

On May 23, 2003, CPN filed a motion to voluntarily withdraw its petition for review, and on June 3, 2003 an order was entered dismissing the case.

**PacifiCorp v. United States**

In September 2002, PacifiCorp, an investor-owned utility, filed an action in the United States District Court for the District of Oregon seeking an order to compel arbitration under the General Transfer Agreement (GTA), a transmission contract between Bonneville and PacifiCorp.

Because of a meter error, PacifiCorp served a Bonneville power load for approximately five months. PacifiCorp is seeking approximately $11 million in damages for this service. It alleges that it provided the service under the GTA and that the dispute is subject to arbitration under that contract.

In November 2002, Bonneville filed its response to PacifiCorp's petition. Bonneville denies that this issue arises under the GTA. Bonneville instead asserts that it is an "inadvertent interchange" of energy, and that under procedures of the Western Electricity Coordinating Council, a reliability organization to which Bonneville and PacifiCorp both belong, PacifiCorp is entitled to return of the power, but not to monetary compensation. Bonneville further asserts that even if the issue arises under the GTA, it is not subject to arbitration under the contract's arbitration clause.

On May 1, 2003, the court granted PacifiCorp's petition to compel arbitration. Bonneville is in the process of analyzing the court's opinion to determine whether to appeal. Settlement discussions have been scheduled.

**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 Claims Court. 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 Claims Court 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 Claims Court on the jurisdictional issue and remanded the Contract Disputes Act matter to the Claims Court.

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 Contract Board of Appeals.

### Residential Exchange Program Litigation

In connection with Subscription, 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. 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.

The briefing schedules have been vacated, the cases have been stayed, and settlement discussions are underway.

### Pacific Northwest Generating Cooperative v. Bonneville Power Administration

In April 2000, Bonneville issued a document entitled "Power Subscription Strategy — Administrator's Supplemental Record of Decision" ("Supplemental Subscription Strategy ROD"). The Supplemental Subscription Strategy ROD was issued to address issues and developments that had occurred since Bonneville issued its original Subscription Strategy Record of Decision in December 1998. The Subscription Strategy Record of Decision, and the Supplemental Subscription Strategy ROD set the course for Bonneville to establish rates and offer power sales contracts upon expiration of previously existing contracts on September 30, 2001.

Shortly after issuance of the Supplemental Subscription Strategy ROD, Bonneville was sued in the Ninth Circuit Court by Vanalco, Inc. (a DSI), and the Pacific Northwest Generating Cooperative ("PNGC") and its members. The PNGC is a consortium of generating cooperative Preference Customers in the Pacific Northwest. Petitioner Vanalco has voluntarily withdrawn from the litigation. In an order dated January 23, 2001, the court vacated the existing briefing schedule and the case was selected for inclusion in the Ninth Circuit Court's mediation program. The case has been stayed pending settlement discussions.

In a related matter, Puget Sound Energy, Inc. filed a petition for review in January 2001 challenging "Slice of the System" contracts executed between Bonneville and certain public utility customers. Puget alleges the contracts violate Bonneville's statutory authorities. The case was selected for inclusion in the Ninth Circuit Court's mediation program, and has been stayed pending settlement discussions.

### 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 by the latter part of April 2001 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.

**California Oregon Intertie (COI) Transmission Dispute**

In March 2000, the Transmission Agency of Northern California ("TANC"), a joint-powers agency of the State of California and a participant in transmission facilities in that state, filed an action against Bonneville, the Sierra Pacific Power Co. ("Sierra Pacific"), PacifiCorp, and the Portland General Electric Company in California state court. TANC challenged Bonneville's participation in the interconnection of its federal transmission facilities with facilities owned and operated by Sierra Pacific ("Alturas Interconnection"). TANC alleged the interconnection adversely affects its rights under agreements related to the Pacific Northwest-Southwest AC Intertie ("COI Transmission Line"). The action was removed to the U.S. District Court for the Eastern District of California. TANC's claims against Bonneville include inverse condemnation, trespass, nuisance, conversion and breach of contract. TANC seeks damages in the amount of $23 million.

In November 2000, Bonneville moved to dismiss TANC's complaint on the basis that the Ninth Circuit Court has exclusive jurisdiction over Bonneville in this matter and other grounds. The other named defendants also moved to dismiss TANC's claims on other grounds. In February 2001, the district court dismissed all claims against Bonneville on a determination that the court lacked jurisdiction to review the claims. The court also dismissed all claims against the other defendants. In March 2001, TANC appealed the district court's decision to the Ninth Circuit Court. The Ninth Circuit Court heard argument on this case in February 2002, and affirmed the dismissal in July 2002. TANC then filed a petition for review by the U.S. Supreme Court. On June 9, 2003, the U.S. Supreme Court denied certiorari, thereby affirming the Ninth Circuit Court's dismissal of the case for lack of jurisdiction.

TANC's complaint in the foregoing litigation is similar to another Bonneville matter before FERC. In 1998, Sierra Pacific sought approval from FERC for the Alturas Interconnection, which FERC granted. Later, in December 1998, Sierra Pacific filed at FERC an operating agreement for the interconnection. TANC and other California public and private utilities intervened in the proceeding, asserting that the interconnection adversely affected reliability of the COI Transmission Line, and FERC set the matter for hearing. In March 2001, the Presiding Administrative Law Judge issued an Initial Decision which substantially supports Bonneville's position. The Initial Decision is on appeal before FERC and the parties await a decision.

**Confederated Tribes of the Umatilla Indian Reservation and the Nez Perce Tribe, *et. al.* v. Bonneville Power Administration**

In November 2001, the Sierra Club and other environmental organizations petitioned the Ninth Circuit Court to review Bonneville's decision document of August 2001 that sets forth certain aspects of the implementation of the 2000 Biological Opinion and compliance with other laws. See "— Power Business Line — Certain Statutes and Other Matters Affecting Bonneville's Power Business Line — Fish and Wildlife — 2000 Biological Opinion." A similar petition was filed by the Confederated Tribes of the Umatilla Indian Reservation and the Nez Perce Tribe. The court has consolidated these petitions. Among other things, the challenged decision document provides guidance for operating the Federal System hydroelectric dams in a manner intended to protect listed fish species under the ESA. The decision document also provides certain exceptions to such operations in the event power generation is needed to address emergency electric system needs.

Petitioners allege that Bonneville's decision document does not comply with provisions of the Northwest Power Act directing Bonneville to exercise its fish and wildlife responsibilities in a manner that provides "equitable treatment" for fish and wildlife with other purposes for which the Federal System facilities are managed and operated. Petitioners seek to vacate the decision document and remand it to Bonneville to make it comply with the Northwest Power Act and other applicable law. Briefing is complete, and oral argument occurred on May 6, 2003.

**Blachly-Lane Electric Cooperative, *et al*. v. Bonneville Power Administration**

A consortium of publicly-owned utilities, municipalities and cooperatives filed a petition for review in the Ninth Circuit Court in September 2001. The petitioners allege that in a Record of Decision dated June 20, 2001, Bonneville decided to sell more power than is available from the Federal Base System resources, including sales to DSIs, resulting in a shift of an estimated $550 million per year in power costs to Bonneville's preference customers. The petitioners allege that Bonneville's actions violated public preference provisions of the Northwest Power Act. Oral argument has been scheduled for July 10, 2003.

**Southern California Edison v. Bonneville Power Administration**

Southern California Edison ("Southern") 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 sales contract between Bonneville and Southern.

In the first petition for review, Southern challenges Bonneville's decision to convert the contract from a sale of power to an exchange of power. In the second petition for review, Southern challenges a Record of Decision issued by Bonneville in its rate adjustment proceeding. Southern alleges that the rate adjustment violates its power sales contract. In the third petition for review, Southern challenges Bonneville's letter to Southern terminating service under its power sales contract due to Southern'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, the cases were dismissed by the U.S. Court of Federal Claims and Southern has filed administrative claims for relief with Bonneville as an apparent predicate to re-filing its claims in the Court of Federal Claims.

In March 2003, Southern re-filed litigation in the Claims Court on the claim that Bonneville breached the contract by converting it from a power sale to a power exchange. In addition, in March 2003 Southern also filed a petition for review in the Ninth Circuit Court. In the case filed in the Ninth Circuit, Southern alleges Bonneville violated Southern's First Amendment right to petition the government for redress of grievances because Bonneville has allegedly altered its trading practices with Southern. The case has been selected for inclusion in the Court's mediation program and the case has been stayed.

**Kevin Bell, *et al.* v. Bonneville Power Administration**

Two petitions for review were filed in the Ninth Circuit Court challenging Bonneville's decisions to execute certain agreements with most of Bonneville's DSIs. These agreements are generally called load reduction or curtailment agreements. The agreements were executed in 2001 to enable Bonneville to reduce its obligations to serve power to these customers, and to buy power back from these customers at below market prices at a time when market prices for power were extremely high. Petitioners allege that Bonneville exceeded its statutory authority and violated ratemaking and resource acquisition provisions of the Northwest Power Act, as well as the National Environmental Policy Act. The case has been briefed and oral argument was heard on May 6, 2003. The Court has not yet issued an opinion.

**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 a group of industrial customers of Northwest utilities, Alcoa, Inc., and some of Bonneville's public utility customers. Numerous other parties have moved to intervene. The case is under consideration for inclusion in the court's mediation program.

**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—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. The court's order gives NOAA Fisheries a year to reconsider the biological opinion. To address the court's concerns, it is possible that a revised biological opinion may increase the forms and extent of mitigation measures beyond those required in the 2000 Biological Opinion as reviewed by the court. If NOAA Fisheries were to include additional or expanded measures in a new or amended biological opinion it is possible that substantial additional costs could be borne by Bonneville.

*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 delisted 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 is 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. NOAA Fisheries has decided to revisit its Hatchery Listing Policy. NOAA Fisheries has not yet officially proposed its amended Hatchery Listing Policy, and the parties await a ruling on the appeal from the Ninth Circuit Court.

### 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 has proposed new power rates for the five years beginning October 1, 2002. Bonneville will propose 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 Services 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.

## NO LITIGATION

There is no litigation pending or threatened in any court (local, state or federal) to restrain or enjoin the issuance or delivery of the 2003 Bonds, or questioning the creation, organization, existence, or title to office of the officers of the District, the validity or enforceability of the 2003 Bonds or the Bond Resolution, the pledge of Cowlitz Falls Revenues or the proceedings for the authorization, execution, sale and delivery of the 2003 Bonds. See "THE COWLITZ FALLS PROJECT — Environmental Issues" for a discussion of environmental litigation concerning the Cowlitz Falls Project. For a discussion of certain litigation involving Bonneville, see "THE BONNEVILLE POWER ADMINISTRATION — Bonneville Litigation."

## TAX EXEMPTION

### GENERAL

In the opinion of Preston Gates & Ellis LLP, Seattle, Washington, Bond Counsel, interest on the 2003 Bonds will be excluded from gross income subject to federal income taxation pursuant to Section 103 of the Internal Revenue Code of 1986 (the "Code"), provided the District complies with arbitrage requirements of Section 148 of the Code described in this section under the heading "Continuing Requirements." The 2003 Bonds are not private activity bonds and interest on the 2003 Bonds is not an item of tax preference for purposes of determining alternative minimum taxable income for individuals or corporations under the Code. However, interest on the 2003 Bonds is taken into account in the computation of adjusted current earnings for purposes of the corporate alternative minimum tax under Section 55 of the Code as more fully described in this section under the heading "Certain Federal Income Tax Consequences."

Except as described herein, Bond Counsel expresses no opinion on any federal, state or local tax consequence arising with respect to ownership of the 2003 Bonds.

## CONTINUING REQUIREMENTS

Section 148 of the Code has continuing arbitrage requirements that must be met subsequent to the issuance of the 2003 Bonds for the interest on the 2003 Bonds to be, and remain, exempt from regular federal income taxation. These requirements include provisions that prescribe investment yield limitations for the proceeds of the 2003 Bonds and that certain investment earnings be paid on a periodic basis to the federal government. The Bond Resolution contains covenants of the District to comply with these continuing arbitrage requirements. Bond Counsel has not undertaken to determine (or to inform any person) whenever any action taken (or not taken) or events occurring (or not occurring) after the date of issuance of the 2003 Bonds may affect the tax status of the interest on the 2003 Bonds.

## CERTAIN FEDERAL INCOME TAX CONSEQUENCES

The following is a discussion of certain federal income tax matters under the Code. This discussion does not purport to deal with all aspects of federal taxation that may be relevant to particular bond owners. Prospective bond owners, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the 2003 Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

***Alternative Minimum Tax on Corporations***. Section 55 of the Code imposes an alternative minimum tax on corporations equal to the excess of the tentative minimum tax for the taxable year over the regular tax for such year. The tentative minimum tax is based upon alternative minimum taxable income which is regular taxable income with certain adjustments and increased by the amount of certain items of tax preference. One of the adjustments is a portion (75% for any taxable year beginning after 1989) of the amount by which a corporation's adjusted current earnings exceeds the corporation's alternative minimum taxable income (determined without regard to such adjustment and the alternative tax net operating loss deduction). Interest on tax-exempt obligations, such as the 2003 Bonds, is included in a corporation's adjusted current earnings.

For taxable years beginning December 31, 1997, the corporate alternative minimum tax is repealed for small business corporations that had average gross receipts of less than $5 million for the three-year period beginning after December 31, 1994, and such small business corporations will continue to be exempt from the corporate alternative minimum tax so long as their average gross receipts do not exceed $7.5 million.

***Financial Institutions***. The Code denies banks, thrift institutions and other financial institutions a deduction for 100% of their interest expense allocable to tax-exempt obligations, such as the 2003 Bonds, acquired after August 7, 1986.

***Borrowed Funds***. The Code provides that interest paid on funds borrowed to purchase or carry tax-exempt obligations during a tax year is not deductible. In addition, under rules used by the Internal Revenue Service for determining when borrowed funds are considered used for the purpose of purchasing or carrying particular assets, the purchase of obligations may be considered to have been made with borrowed funds even though the borrowed funds are not directly traceable to the purchase of such obligations.

***Property and Casualty Insurance Companies***. The deduction for loss reserves for property and casualty insurance companies is reduced by 15% of the sum of certain items, including the interest received on tax-exempt bonds, such as the 2003 Bonds.

***Social Security and Railroad Retirement Benefits***. The Code also requires recipients of certain Social Security or Railroad Retirement benefits to take into account, in determining gross income, receipts or accruals of interest that is exempt from federal income tax, such as the 2003 Bonds.

***Branch Profits Tax***. Certain foreign corporations doing business in the United States may be subject to a branch profits tax on their effectively connected earnings and profits, including tax-exempt interest on obligations, such as interest on the 2003 Bonds.

***S Corporations***. Certain S corporations that have subchapter C earnings and profits at the close of a taxable year and gross receipts more than 25% of which are passive investment income, which includes interest on tax-exempt obligations, such as interest on the 2003 Bonds, may be subject to a tax on excess net passive income.

## TAX TREATMENT OF PREMIUM ON BONDS

Certain maturities of the 2003 Bonds as set forth on the cover page of this Official Statement will be reoffered to members of the public (excluding bond houses, brokers and other intermediaries acting in the capacity of wholesalers or underwriters) at an initial offering price which exceeds the stated redemption price payable at the maturity of such 2003 Bonds. Such 2003 Bonds (the "Premium Bonds") will be considered for federal income tax purposes to have "bond premium" equal to the amount of such excess. The basis for federal income tax purposes of a Premium Bond in the hands of an initial purchaser who purchases such Premium Bond in the initial offering must be reduced each accrual period and upon the sale or other taxable disposition of the Premium Bond by the amount of amortizable bond premium. This reduction in basis will increase the amount of any gain (or decrease the amount of any loss) recognized for federal income tax purposes on the sale or other taxable disposition of a Premium Bond by the initial purchaser. No corresponding deduction is allowed for federal income tax purposes, however, for the reduction in basis resulting from amortizable bond premium. The amount of bond premium on a Premium Bond which is amortizable each accrual period (or shorter period in the event of a sale or disposition of a Premium Bond) is determined under special tax accounting rules which use a constant yield throughout the term of the Premium Bond based on the initial purchaser's original basis in such Premium Bond.

The bond premium and federal income tax consequences of the purchase, ownership, redemption, sale or other disposition by an owner of a Premium Bond which is not purchased in the initial offering or which is purchased at a price other than the initial offering price for the Premium Bonds of the same maturity may be determined according to rules which differ from those described above. Moreover, all prospective purchasers of Premium Bonds should consult their tax advisors with respect to the federal, state, local and foreign tax consequences of the purchase, ownership, redemption, sale or other disposition of Premium Bonds.

## RATINGS

Moody's Investors Service ("Moody's") and Standard & Poor's, a Division of The McGraw-Hill Companies, Inc. ("S&P") have assigned their municipal bond ratings of Aa1 and AA-, respectively, to the 2003 Bonds maturing in 2005, 2006 and $1,880,000 of the 2003 Bonds maturing in 2007 and Aaa and AAA, respectively, to the $3,050,000 of the 2003 Bonds maturing in 2007 and the 2003 Bonds maturing in 2008 through 2012 on the condition that upon delivery of the 2003 Bonds XL Capital Assurance Inc. and MBIA Insurance Corporation deliver their bond insurance policies.

Such ratings reflect only the views of the rating organizations, and an explanation of the significance of the ratings may be obtained from the rating agencies as follows: Moody's Investors Service, 99 Church Street, New York, New York 10007, (212) 553-0300 and Standard & Poor's, a Division of The McGraw-Hill Companies, Inc., 55 Water Street, New York, New York 10041, (212) 438-7280. There is no assurance that the ratings will continue for any given period of time or that they will not be revised downward or withdrawn entirely by the rating agencies, if, in the judgment of the agencies, circumstances so warrant. Any such reduction or withdrawal of such ratings may have an adverse effect on the market price of the 2003 Bonds.

## UNDERWRITING

The Underwriters have agreed, subject to certain conditions, to purchase the 2003 Bonds from the District at the aggregate prices or yields set forth on the cover of this Official Statement less an underwriting discount of $765,969.45, including an original issue premium of $12,305,097.40. The Underwriters will be obligated to purchase all of 2003 Bonds if any are purchased. The Underwriters have advised the District that the 2003 Bonds may be offered and sold to certain dealers (including other dealers depositing 2003 Bonds into investment trusts) at prices lower than the initial public offering prices, and the initial public offering prices may be changed from time to time by the Underwriters.

## CERTAIN LEGAL MATTERS

All legal matters incident to the authorization and issuance of the 2003 Bonds are subject to the approval of Preston Gates & Ellis LLP, Bond Counsel, Seattle, Washington, whose approving opinion in substantially the form attached hereto as Appendix C will be delivered to the District and to the Underwriters in connection with the issuance of the 2003 Bonds. Certain legal matters will be passed upon for the Underwriters by their counsel, Foster Pepper & Shefelman, PLLC and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. From time to time, Preston Gates & Ellis LLP and Orrick, Herrington & Sutcliffe LLP serve as counsel to the Underwriters on unrelated transactions. Any opinion of Underwriters' counsel will be rendered solely to the Underwriters, will be limited in scope, and is not to be relied upon by investors without the prior written consent of such counsel.

## CONTINUING DISCLOSURE UNDERTAKING

In accordance with Section (b)(5) of Securities and Exchange Commission Rule 15c2-12 under the Securities and Exchange Act of 1934, as the same may be amended from time to time (the "Rule"), the District has agreed in the Bond Resolution and Bonneville will agree to provide or cause to be provided to each nationally recognized municipal securities information repository ("NRMSIR") and to the state information depository for the State (if one is created) ("SID"), in each case as designated by the Securities and Exchange Commission (the "Commission") in accordance with the Rule, the following annual financial information and operating data for the prior fiscal year:

1. Audited financial statements of the Cowlitz Falls Project prepared in accordance with generally accepted accounting principles applicable to government entities, with regulations prescribed by the Washington State Auditor pursuant to RCW 43.09.200 (or any successor statute) provided that, if the Cowlitz Falls Project's financial statements are not yet available, the District shall provide unaudited financial statements in substantially the same format, and audited financial statements when they become available. Such annual information and operating data shall be available on or before nine months after the end of the District's fiscal year (commencing in 2004 for the fiscal year ended December 31, 2003). The District's current fiscal year ends December 31. The District may adjust such fiscal year by providing written notice of the change of fiscal year to each then existing NRMSIR and the SID, if any. In lieu of providing such annual financial information and operating data, the District may cross-reference to other documents the District provides to the NRMSIRs and the SID or to the Commission and, if such document is a final official statement within the meaning of the Rule, available from the Municipal Securities Rulemaking Board ("MSRB");

2. Audited financial statements of Bonneville prepared in accordance with generally accepted accounting principles; provided, that if Bonneville's financial statements are not yet available, Bonneville shall provide unaudited financial statements in substantially the same format and audited financial statements when they become available. Bonneville shall provide its financial statements within 180 days after its fiscal year, which currently ends September 30; and

3. The Bonneville Annual Information relating to such fiscal year. The Bonneville Annual Information shall consist of the following: financial information and operating data of the type included in this Official Statement in the following tables under the heading "THE BONNEVILLE POWER ADMINISTRATION": "Operating Federal System Projects for Operating Year 2003," "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."

The District and Bonneville agree 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 failure to provide the annual financial information described above on or prior to the date set forth above.

The District further 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 2003 Bonds, if material:

- ♦ Principal and interest payment delinquencies;

- Nonpayment related defaults;
- Unscheduled draws on debt service reserves reflecting financial difficulties;
- Substitution of credit or liquidity providers or their failure to perform;
- Unscheduled draws on credit enhancements reflecting financial difficulties;
- Adverse tax opinions or events affecting the tax-exempt status of the 2003 Bonds;
- Modifications to rights of 2003 Bondholders;
- 2003 Bond calls (other than mandatory sinking fund redemptions);
- Defeasances;
- Rating changes; and
- Release, substitution or sale of property securing repayment of the 2003 Bonds.

The District's and Bonneville's obligations to provide annual financial information, and the District's obligation to provide notices of material events, shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2003 Bonds. Such undertakings, or any provision thereof, shall be null and void if the District and Bonneville (1) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule which require the undertakings, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the 2003 Bonds; and (2) notifies each then existing NRMSIR and the SID, if any, of such opinion and the cancellation of such undertaking.

Notwithstanding any other provision of the Bond Resolution, the District and Bonneville may amend their undertakings, without the consent of any 2003 Bondholder, with an approving opinion of bond counsel that the amendment is in accordance with the Rule.

The District or Bonneville, as appropriate, will give notice to each NRMSIR or the MSRB, and the SID, if any, of the substance (or provide a copy) of any amendment to its undertaking and a brief statement of the reasons for the amendment. If the amendment changes the type of annual financial information to be provided, the notice also will include a narrative explanation of the effect of that change on the type of information to be provided.

A 2003 Bond owner's or Beneficial Owner's right to enforce the provisions of the District's undertaking described under this heading shall be limited to a right to obtain specific enforcement of the District's obligations. A 2003 Bond owner's or Beneficial Owner's right to enforce the provisions of Bonneville's undertaking described under this heading shall be limited to a right to obtain specific performance of Bonneville's obligations if specific performance is a permitted remedy against Bonneville under federal law and, if it is not then permitted, to exercise any rights available to it under federal law with respect to remedies against Bonneville. Any failure by the District or Bonneville to comply with the provisions of this undertaking shall not be an event of default with respect to the 2003 Bonds. For purposes of this section, "Beneficial Owner" means any person who has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of, any 2003 Bonds, including persons holding 2003 Bonds through nominees or depositories.

**PRIOR COMPLIANCE WITH CONTINUING DISCLOSURE UNDERTAKINGS**

The District has not entered into any prior continuing disclosure undertakings. Bonneville has complied with its prior written undertakings under the Rule.

## MISCELLANEOUS

Any statements in this Official Statement involving matters of opinion, whether or not expressly so stated, are intended as such, and are not a representation of fact. This Official Statement is not to be construed as an agreement or contract between the District and the purchasers or owners of any 2003 Bonds.

PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY, WASHINGTON

/s/ David J. Muller
Manager

# Report of Independent Accountants

PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying balance sheets and the related statements of changes in capitalization and long-term liabilities and of revenues and expenses, of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2002 and 2001, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2002, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2002, 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 which 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.

Our audit was conducted 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, 2002 (Schedule A) is presented for purposes of additional analysis and is 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
December 16, 2002

## Financial Statements

### Statements of Revenues and Expenses

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

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| **Operating Revenues** | | | |
| Sales | $ 3,407,404 | $ 3,563,182 | $ 2,903,735 |
| SFAS 133 mark-to-market | 38,354 | 47,877 | — |
| Miscellaneous Revenues | 49,571 | 66,902 | 103,251 |
| U.S. Treasury Credits for Fish | 38,400 | 600,708 | 60,000 |
| Total operating revenues | 3,533,729 | 4,278,669 | 3,066,986 |
| **Operating Expenses** | | | |
| Operations and maintenance | 1,319,707 | 1,023,180 | 977,439 |
| Purchased power | 1,286,867 | 2,296,076 | 633,142 |
| Nonfederal projects (Note 4) | 230,175 | 473,100 | 560,836 |
| Federal projects depreciation | 335,205 | 323,314 | 319,942 |
| Total operating expenses | 3,171,954 | 4,115,670 | 2,491,359 |
| Net operating revenues | 361,775 | 162,999 | 575,627 |
| **Interest Expense** | | | |
| Interest on federal investment: | | | |
| Appropriated funds (Note 3) | 258,195 | 248,429 | 248,352 |
| Long-term debt (Note 2) | 151,997 | 129,159 | 115,052 |
| Allowance for funds used during construction | (57,892) | (45,679) | (28,754) |
| Net interest expense | 352,300 | 331,909 | 334,650 |
| Net revenues (expenses) before cumulative effect of SFAS 133 | 9,475 | (168,910) | 240,977 |
| **Cumulative effect of SFAS 133** | — | (168,491) | — |
| **Net Revenues (Expenses)** | 9,475 | (337,401) | 240,977 |
| Accumulated net (expenses) revenues, Oct. 1 | (221,151) | 132,810 | (108,167) |
| Irrigation Assistance | — | (16,560) | — |
| Accumulated net (expenses) revenues, Sept. 30 | **$ (211,676)** | **$ (221,151)** | **$ 132,810** |

*The accompanying notes are an integral part of these statements.*

# Balance Sheets

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

## Assets

| | 2002 | 2001 |
|---|---|---|
| **Utility Plant** (Notes 1 and 3) | | |
| Completed plant | $ 11,488,047 | $ 11,249,158 |
| Accumulated depreciation | (4,052,117) | (3,817,309) |
| | 7,435,930 | 7,431,849 |
| Construction work in progress | 1,200,179 | 913,670 |
| Net utility plant | 8,636,109 | 8,345,519 |
| **Nonfederal Projects** (Note 4) | | |
| Conservation | 47,733 | 50,189 |
| Hydro | 167,080 | 170,730 |
| Nuclear | 2,127,907 | 2,116,473 |
| Terminated hydro facilities | 29,555 | 30,245 |
| Terminated nuclear facilities | 3,829,269 | 3,804,312 |
| Total nonfederal projects | 6,201,544 | 6,171,949 |
| **Trojan Decommissioning Cost** (Note 5) | 73,861 | 69,221 |
| **Conservation**, net of accumulated amortization of $831,631 in 2002 and $769,221 in 2001 (Notes 1 and 2) | 409,571 | 444,021 |
| **Fish and Wildlife**, net of accumulated amortization of $129,207 in 2002 and $110,954 in 2001 (Notes 1 and 2) | 134,204 | 146,354 |
| **Current Assets** | | |
| Cash | 235,409 | 667,306 |
| Accounts receivable | 299,040 | 387,805 |
| Materials and supplies, at average cost | 85,107 | 85,222 |
| Prepaid expenses | 285,696 | 187,149 |
| Total current assets | 905,252 | 1,327,482 |
| **Other Assets** | 151,458 | 265,984 |
| | **$ 16,511,999** | **$ 16,770,530** |

*The accompanying notes are an integral part of these statements.*

## Capitalization and Liabilities

| | 2002 | 2001 |
|---|---|---|
| **Capitalization and Long-Term Liabilities** | | |
| Accumulated net expenses (Note 1) | $ (211,676) | $ (221,151) |
| Federal appropriations (Note 3) | 4,595,915 | 4,647,017 |
| Capitalization adjustment (Note 3) | 2,192,400 | 2,259,756 |
| Long-term debt (Note 2) | 2,563,141 | 2,582,542 |
| Nonfederal projects debt (Note 4) | 5,958,538 | 5,954,490 |
| Trojan decommissioning reserve (Note 5) | 63,861 | 57,221 |
| Total capitalization and long-term liabilities | 15,162,179 | 15,279,875 |
| **Commitments and Contingencies** (Notes 5 and 6) | | |
| **Current Liabilities** | | |
| Current portion of federal appropriations | 46,687 | 23,913 |
| Current portion of long-term debt | 207,300 | 106,000 |
| Current portion of nonfederal projects debt | 243,006 | 217,459 |
| Current portion of Trojan decommissioning reserve | 10,000 | 12,000 |
| Accounts payable and other current liabilities | 343,425 | 510,957 |
| Total current liabilities | 850,418 | 870,329 |
| **Deferred Credits** (Note 1) | 499,402 | 620,326 |
| | **$16,511,999** | **$16,770,530** |

## Statements of Changes in Capitalization and Long-Term Liabilities

*Federal Columbia River Power System*
*Including current portions — Thousands of dollars*

| | Accumulated Net Revenues (Expenses) | Federal Appropriations | Long-Term Debt | Nonfederal Project Debt | Other | Total |
|---|---|---|---|---|---|---|
| **Balance at Sept. 30, 2000** | **$ 132,810** | **$4,566,011** | **$2,513,200** | **$6,408,865** | **$2,406,847** | **$16,027,733** |
| Increase in federal appropriations: | | | | | | |
| Construction | — | 230,388 | — | — | — | 230,388 |
| Repayment of federal appropriations: | | | | | | |
| Construction | — | (125,469) | — | — | — | (125,469) |
| Capitalization adjustment amortization | — | — | — | — | (68,784) | (68,784) |
| Irrigation Assistance | (16,560) | — | — | — | — | (16,560) |
| Increase in long-term debt | — | — | 260,000 | — | — | 260,000 |
| Repayment of long-term debt | — | — | (84,658) | — | — | (84,658) |
| Net decrease in nonfederal projects debt | — | — | — | (60,658) | — | (60,658) |
| Repayment of nonfederal projects debt | — | — | — | (176,258) | — | (176,258) |
| Trojan decommissioning reserve | — | — | — | — | (9,086) | (9,086) |
| Net expenses | (337,401) | — | — | — | — | (337,401) |
| **Balance at Sept. 30, 2001** | **$ (221,151)** | **$4,670,930** | **$2,688,542** | **$6,171,949** | **$2,328,977** | **$15,639,247** |
| Increase in federal appropriations: | | | | | | |
| Construction | — | 168,583 | — | — | — | 168,583 |
| Repayment of federal appropriations: | | | | | | |
| Construction | — | (196,911) | — | — | — | (196,911) |
| Capitalization adjustment amortization | — | — | — | — | (67,356) | (67,356) |
| Increase in long-term debt | — | — | 390,000 | — | — | 390,000 |
| Repayment of long-term debt | — | — | (308,101) | — | — | (308,101) |
| Net increase in nonfederal projects debt | — | — | — | 258,775 | — | 258,775 |
| Repayment of nonfederal projects debt | — | — | — | (229,180) | — | (229,180) |
| Trojan decommissioning reserve | — | — | — | — | 4,640 | 4,640 |
| Net revenues | 9,475 | — | — | — | — | 9,475 |
| **Balance at Sept. 30, 2002** | **$ (211,676)** | **$4,642,602** | **$2,770,441** | **$6,201,544** | **$2,266,261** | **$15,669,172** |

*The accompanying notes are an integral part of these statements.*

## Statements of Cash Flows

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

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| **Cash from Operating Activities** | | | |
| Net revenues (expenses) | $ 9,475 | $ (337,401) | $ 240,977 |
| Expenses (income) not requiring cash: | | | |
| Depreciation | 254,332 | 247,247 | 242,673 |
| Amortization of conservation and fish and wildlife | 78,047 | 76,067 | 77,269 |
| Amortization of nonfederal projects | 229,180 | 176,258 | 323,619 |
| Amortization of capitalization adjustment | (67,356) | (68,784) | (67,474) |
| AFUDC | (57,892) | (45,679) | (28,754) |
| (Increase) decrease in: | | | |
| Accounts receivable | 88,765 | (31,283) | (155,444) |
| Materials and supplies | 115 | (20,930) | 6,785 |
| Prepaid expenses | (98,547) | (101,254) | (3,200) |
| Increase (decrease) in: | | | |
| Accounts payable | (167,532) | 138,687 | 100,699 |
| Other | (6,399) | 114,060 | 8,437 |
| Cash provided by operating activities | 262,188 | 146,988 | 745,587 |
| **Cash from Investment Activities** | | | |
| Investment in: | | | |
| Utility plant | (487,030) | (399,220) | (310,165) |
| Conservation | (25,344) | 141 | — |
| Fish and wildlife | (6,102) | (16,493) | (13,898) |
| Cash used for investment activities | (518,476) | (415,572) | (324,063) |
| **Cash from Borrowing and Appropriations** | | | |
| Increase in federal constructions appropriations | 168,583 | 230,388 | 129,953 |
| Repayment of federal construction appropriations | (196,911) | (125,469) | (62,425) |
| Irrigation assistance | — | (16,560) | — |
| Increase in long-term debt | 390,000 | 260,000 | 294,300 |
| Repayment of long-term debt | (308,101) | (84,658) | (227,500) |
| Refinance of long-term debt | — | — | (68,800) |
| Payment of nonfederal debt | (229,180) | (176,258) | (323,619) |
| Cash (used for) provided by borrowing and appropriations | (175,609) | 87,443 | (258,091) |
| (Decrease) increase in cash | (431,897) | (181,141) | 163,433 |
| Beginning cash balance | 667,306 | 848,447 | 685,014 |
| **Ending cash balance** | **$ 235,409** | **$ 667,306** | **$ 848,447** |

*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), which purchases, transmits and markets power, and the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) for which BPA is the power marketing agency. 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 is 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.

### 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 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.

### Standards of Ethical Conduct

As part of the United States federal government, employees of the FCRPS are bound by Standards of Ethical Conduct for Employees of the Executive Branch. The Standards contains 14 general principles that address topics such as placing ethical principles above private gain, not engaging in conflicts of interest, not using public office for private gain, and complying with all applicable governmental rules and regulations. The Standards document spells out these principles in great detail and includes examples of how to respond in situations where ethical dilemmas arise. All employees of the FCRPS, including executives, are required to receive federal ethics training and sign a document stating they understand the Standards of Ethical Conduct on an annual basis.

### Reclassifications

Certain reclassifications were made to the 2000 and 2001 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2002. Such reclassifications had no effect on previously reported results of operations and cash flows.

### Regulatory Authority

BPA's 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 established by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the National Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power, for nonfirm energy sold within the region, 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. FERC and 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. By contract, 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 sets of conditions in which rate increases under the CRACs may trigger. 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 second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of accumulated net revenues is below a pre-determined 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 reasonably expects to miss a payment to the Treasury or another creditor. Of these certain rate adjustment clauses, some are calculated on forward-looking market conditions and adjustments are made after-the-fact when actual conditions are known. These adjustments result in an additional charge or rebate due 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 percent for the first half of fiscal 2002 compared to base rates. The LB CRAC percentage changes every 6 months. The increase was 41 percent for the second half of fiscal 2002. The LB CRAC percentage will be revised for the six-month periods beginning Oct. 1, 2002 and April 1, 2003.

At Sept. 30, 2002, BPA has recognized a liability of $5.8 million for the LB CRAC period ended March 31, 2002, and a receivable of $2.3 million for the LB CRAC ended Sept. 30, 2002. The August forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a one-year rate increase beginning Oct. 1, 2002, of approximately 11 percent for most of the requirement rates on top of the revised levels of the LB CRAC. SN CRAC did not trigger in fiscal 2002.

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 percent of BPA's power costs in exchange for a fixed percent of generation and capabilities. Settlement of any over or under collection is in the subsequent year. For the fiscal 2002 settlement, BPA has recognized a receivable of $49 million to be received in fiscal 2003.

FERC granted final approval for proposed Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA submitted a separate Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on October 11, 2001, FERC granted final approval for corrections of the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001).

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) No. 71, Accounting for the Effects of Certain Types of Regulation.

### SFAS 71 Assets

*As of Sept. 30 — Thousands of dollars*

| | 2002 | 2001 |
|---|---|---|
| **Nonfederal projects** | | |
| Conservation | $ 47,733 | $ 50,189 |
| Terminated nuclear facilities | 3,829,269 | 3,804,312 |
| Terminated hydro facilities | 29,555 | 30,245 |
| **Trojan decommissioning cost** | 73,861 | 69,221 |
| **Conservation** | 409,571 | 444,021 |
| **Fish and wildlife** | 134,204 | 146,354 |
| **Additional retirement contributions** | 36,800 | 68,100 |
| **Total** | **$ 4,560,993** | **$ 4,612,442** |

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.

The SFAS 71 assets of $4.6 billion, shown in the table on page 31, reflect a decrease of $51 million from the prior year. Amortization of these costs aggregating $293 million in fiscal 2002, $259 million in 2001 and $276 million in fiscal 2000 is reflected in the Statements of Revenues and Expenses.

### Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $93 million at Sept. 30, 2002, and $6 million at Sept. 30, 2001. Estimated unbilled revenues are included in accounts receivable in the accompanying Balance Sheets. BPA operates as two segments: The Power Business Line and the Transmission Business Line. The table in Note 7 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 5.

### 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. In accordance with FERC requirements the cost of utility plant retired, together with removal costs less salvage, is charged to accumulated depreciation when it is removed from service.

### 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 (CWIP) balance. A portion of CWIP as stated on the balance sheets represents study and investigation costs to which AFUDC is not attributed.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects (2.5 percent to 6.5 percent in 2002, 2.5 percent to 6.6 percent in 2001 and 2.5 percent to 6.7 percent in 2000). Capitalization rates for other construction approximate the cost of borrowing from the U.S. Treasury (6.0 percent in 2002, 6.5 percent in 2001 and 6.6 percent in 2000).

### 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 10 to 20 years for conservation and 15 years for fish and wildlife.

### Fish Credits

The Act 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. It 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.

BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism against Bonneville's Treasury payments to reimburse BPA for expenditures made on behalf of mitigation for non-power purposes. Under the agreed-upon crediting mechanism, BPA reduces its cash payments to Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes. The credits are used to recoup the amount owed to BPA by the other project purposes. Bonneville has taken this credit since 1995, in amounts that, with the exception of FY 2001, ranged between $26 million and $60 million.

### IOU Subscription Settlement Agreements and Residential Exchange

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), 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.

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 Oct. 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements determining exchange benefits for the period from July 1, 2001 through Sept. 30, 2011. These agreements provide for both sales of power and payments to the IOUs. The table below summarizes future IOU benefits as of Sept. 30, 2002.

### Exchange Benefits

*Thousands of dollars*

| IOU Benefits | |
|---|---|
| 2003 | $ 359,850 |
| 2004 | 359,850 |
| 2005 | 359,850 |
| 2006 | 359,850 |
| **Total** | **$ 1,439,400** |

Benefits beyond the current rate case period cannot currently be quantified.

### Retirement Benefits

FCRPS employees belong to either the Civil Service Retirement System (CSRS) or the Federal Employees' Retirement System (FERS). FCRPS and its employees contribute to the systems. Based on the statutory contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is variable based upon options chosen by the participant but does not exceed 24.2 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

Beginning in fiscal 1998, and for the remainder of the rate period ended in 2001, FCRPS agreed to contribute additional amounts as a result of an underfunded status of the CSRS. These amounts have been calculated based on an estimate of FCRPS employees who participate in the plan as well as an estimate of FCRPS' share of the underfunded status. These contributions are projected over a period of years as shown in the table. The payments, when made, will be directly to the U.S. Treasury.

BPA paid approximately $55.2 million and $8.0 million to the U.S. Treasury during fiscal 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $36.8 million as of Sept. 30, 2002, which represents the additional deferred contribution for fiscal 1998, 1999, 2000, 2001 and 2002. This amount has been recorded as an SFAS 71 asset on the balance sheet for recovery of the costs through rates in the period beginning Oct. 1, 2001. The related liability is included in other current liabilities and deferred credits in the accompanying Balance Sheet. At Sept. 30, 2002, BPA has scheduled additional payments totaling $136.8 million as follows.

### Scheduled Additional CSRS Contributions

*Millions of dollars*

| Scheduled Contributions | |
|---|---|
| 2003 | $ 35.1 |
| 2004 | 30.9 |
| 2005 | 26.5 |
| 2006 | 23.2 |
| 2007 | 21.1 |
| **Total** | **$ 136.8** |

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

## Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and the Corps. Cash paid for interest was $484 million in 2002, $464 million in 2001 and $403 million in 2000.

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 $259 million in 2002, $61 million in 2001 and $40 million in 2000.

## 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 U.S. Government securities and agencies. BPA's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased capacity, energy, or other products and services. These customers are generally large and stable and do not represent a significant concentration of credit risk.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of the company.

In conjunction with the financial reviews, BPA often obtains credit support in the form of parental guarantees and letters of credit to support established credit limits. BPA also utilizes netting agreements to mitigate the credit risk of financial instruments.

Bonneville has open purchase and sales contracts with a diverse group of customers including Enron Power Marketing Inc. (Enron). Enron and its parent company, Enron Corp. filed for bankruptcy protection in December 2001. Due to the nature of the contracts with Enron, management does not consider it necessary to record a provision for loss or for uncollectible amounts as of Sept. 30, 2002, relating to Enron transactions.

### Credit Risk from California

California power markets have been in turmoil for several years, having experienced historically high power prices and volatility. 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) have resulted in concerns by energy suppliers that the Cal-ISO may not be a creditworthy supplier. 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.

Bonneville entered into certain power sales through the Cal-PX for which Bonneville has not yet been paid. In addition Bonneville sold power and related services to the Cal-ISO for which Bonneville has not yet been paid in full. Bonneville also has a long-term seasonal power exchange agreement with Southern California Edison. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, Bonneville has recorded provisions for uncollectible receivable and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

## Deferred Credits

Deferred credits consist of $127 million paid to BPA from participants under the 3rd AC intertie capacity agreement, $126.4 million in advances from customers for projects which BPA is constructing on their behalf, $95.2 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $82.3 million current fair market value of purchased and written options and certain trading physical forward sales and purchases, $23.7 million leasing fees for fiber optic cable, $23.4 million in deferred CSRS, $21.1 million in unearned option premium revenue, and $.3 million in other miscellaneous long-term liabilities.

Deferred 3rd AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets. Advances on projects BPA constructs for customers are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or if BPA retains title, are recorded to revenue over the related useful lives of the assets. Diversification fees are payments by customers to BPA in consideration for a reduction in their contractually obligated power purchases from BPA. Deferred diversification fees and other settlement payments for long-term agreements are recognized as revenue over the original contract terms (diversification fee contracts generally correspond to the rate period ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020. The current portion of deferred credits to be recorded as revenue in fiscal 2002 is included in accounts payable and other current liabilities in the Balance Sheet.

## 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. BPA had no material hedging or financial instruments outstanding as of Sept. 30, 2002.

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2002.

As of and for the years ended Sept. 30, 2002 and 2001, both the deferred and the realized gains and losses resulting from these transactions were not material to the consolidated FCRPS financial statements.

## Written Options

BPA sells put and call options for the purchase and sale of electricity at certain points in the future. BPA's intention is to fulfill all call options exercised with its estimated surplus generating capability at the future dates and to take delivery of power as a result of written put options if exercised. The megawatt-hour quantities that BPA sells and the premiums that BPA collects for the sales of these options are 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 resulting in the requirement that BPA fulfill these sales obligations with power purchases at a cost in excess of the prices stated in the contracts. In addition, BPA may be required to buy power at strike prices above market prices as a result of its written put option obligations.

As of Sept. 30, 2002, there were no written call options outstanding compared to 409,600 megawatt-hours outstanding with an average strike price of $130.25 per megawatt-hour as of Sept. 30, 2001. As of Sept. 30, 2002, written put options totaling 3,507,600 megawatt-hours were outstanding with an average strike price of $42.25 per megawatt-hour compared to 10,112,003 megawatt-hours outstanding as of Sept. 30, 2001. These options expire at various times through Dec. 2005. BPA records written options on a mark-to-market basis and includes gains and losses in operating revenues in the Statement of Revenues and Expenses.

## Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2002 and 2001. The carrying value reflected in the Balance Sheet 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.

## Adoption of Statement 133

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. SFAS 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivatives be reported in net income or other comprehensive income, as appropriate.

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 paragraph 4 (a), and Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." 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. Bonneville may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 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 revenue (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). While authoritative guidance in this area continued to emerge during fiscal year 2001, BPA management elected to apply the most current guidance available.

On June 29, 2001, the FASB issued definitive 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. 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 outside of the scope of SFAS 133 and therefore are not required to be marked to fair value in the financial statements. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

For the fiscal year ended Sept. 30, 2002 Statement of Revenues and Expenses BPA recorded $38.4 million of gains from SFAS 133 fair value application related to certain option and physical forward sales and purchase transactions. This included a $61.3 million gain for open option contracts and a $(22.9) million loss for certain physical forward sales and purchase transactions.

## Recent Accounting Pronouncements

In June 2001, FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." Evaluations of SFAS 141 and 142 have been completed and we have determined there is no current effect on FCRPS financial statements.

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. BPA is continuing to determine the impact, if any, of SFAS 143 on BPA's financial statements. If applicable, SFAS 143 will be effective for BPA starting with the fiscal year ending Sept. 30, 2003.

In August 2001, FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. An evaluation of SFAS 144 has been completed and we have determined there is no current effect on FCRPS financial statements.

In April 2002, FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," and in June 2002, FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit of Disposal Activities." Evaluations of SFAS 145 and 146 have been completed and we have determined there is no current effect on FCRPS financial statements.

## 2. Long-Term Debt

To finance its capital programs, BPA is authorized by the Federal Columbia River Transmission System Act to issue to the U.S. Treasury up to $3.75 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $3.75 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2002, $350 million of this reserved amount and $2,420 million of other borrowings were outstanding. 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 the BPA long-term debt, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2002, for similar maturities exceeds carrying value by approximately $497 million, or 18 percent. The table below reflects the terms and amounts of long-term debt.

### U.S. Treasury Bonds

*Long-Term Debt (a) — Thousands of dollars*

| | First Call Date | Maturity Date | Interest Rate | Construction and Fish & Wildlife | Conservation | Cumulative Total |
|---|---|---|---|---|---|---|
| November 1999 | none | 2002 | 6.40% | $ 40,000 | | $ 40,000 |
| January 1996 | none | 2003 | 5.90% | 60,000 | | 100,000 |
| September 1999 | none | 2003 | 6.30% | 20,000 | | 120,000 |
| April 2000 (b) | none | 2003 | 6.85% | 40,000 | | 160,000 |
| July 2000 | none | 2003 | 6.95% | | $ 32,000 | 192,000 |
| August 2000 | none | 2003 | 6.85% | 15,300 | | 207,300 |
| January 1997 | none | 2004 | 6.80% | 30,000 | | 237,300 |
| May 1999 | none | 2004 | 5.95% | 26,200 | | 263,500 |
| September 1999 (b) | none | 2004 | 6.40% | 20,000 | | 283,500 |
| July 2000 | none | 2004 | 7.00% | 50,000 | | 333,500 |
| June 2001 (b) | none | 2004 | 4.75% | 50,000 | | 383,500 |
| May 1997 | none | 2005 | 6.90% | 80,000 | | 463,500 |
| January 2000 | none | 2005 | 7.15% | 53,500 | | 517,000 |
| September 2000 (b) | none | 2005 | 6.70% | 20,000 | | 537,000 |
| January 2001 | none | 2005 | 5.65% | 20,000 | | 557,000 |
| January 2001 | none | 2005 | 5.65% | 25,000 | | 582,000 |
| March 2002 | none | 2005 | 4.60% | 110,000 | | 692,000 |
| March 2002 (b) | none | 2005 | 4.60% | 30,000 | | 722,000 |
| June 2002 | none | 2005 | 3.75% | 60,000 | | 782,000 |
| June 2002 | none | 2005 | 3.75% | | 40,000 | 822,000 |
| August 1996 | none | 2006 | 7.05% | 70,000 | | 892,000 |
| September 2000 | none | 2006 | 6.75% | 40,000 | | 932,000 |
| September 2002 | none | 2006 | 3.05% | 100,000 | | 1,032,000 |
| September 2002 | none | 2006 | 3.05% | 30,000 | | 1,062,000 |
| September 2002 (b) | none | 2006 | 3.05% | 20,000 | | 1,082,000 |
| August 1997 | none | 2007 | 6.65% | 111,300 | | 1,193,300 |
| April 1998 | none | 2008 | 6.00% | 75,300 | | 1,268,600 |
| April 1998 (b) | none | 2008 | 6.00% | 25,000 | | 1,293,600 |
| August 1998 | none | 2008 | 5.75% | 40,000 | | 1,333,600 |
| September 1998 | none | 2008 | 5.30% | | 104,300 | 1,437,900 |
| July 1989 | none | 2009 | 8.55% | | 40,000 | 1,477,900 |
| May 1998 | none | 2009 | 6.00% | 72,700 | | 1,550,600 |
| May 1998 | none | 2009 | 6.00% | | 37,700 | 1,588,300 |
| January 2001 | none | 2010 | 6.05% | 30,000 | | 1,618,300 |
| January 2001 | none | 2010 | 6.05% | 60,000 | | 1,678,300 |
| January 1996 | 2001 | 2011 | 6.70% | | 30,000 | 1,708,300 |
| November 1996 | 2001 | 2011 | 6.95% | 40,000 | | 1,748,300 |
| May 1998 | none | 2011 | 6.20% | 40,000 | | 1,788,300 |
| June 2001 | none | 2011 | 5.95% | 25,000 | | 1,813,300 |
| August 2001 | none | 2011 | 5.75% | 50,000 | | 1,863,300 |
| January 1998 | none | 2013 | 6.10% | 60,000 | | 1,923,300 |
| September 1998 | none | 2013 | 5.60% | | 52,800 | 1,976,100 |
| January 1994 | 1999 | 2014 | 6.75% | | 13,265 | 1,989,365 |
| February 1999 | none | 2014 | 5.90% | 60,000 | | 2,049,365 |
| July 1995 | 2000 | 2025 | 7.70% | 34,976 | | 2,084,341 |
| April 1998 | 2008 | 2028 | 6.65% | 50,000 | | 2,134,341 |
| August 1998 | none | 2028 | 5.85% | 106,500 | | 2,240,841 |
| August 1998 | none | 2028 | 5.85% | 112,300 | | 2,353,141 |
| May 1998 | 2008 | 2032 | 6.70% | 98,900 | | 2,452,041 |
| August 1993 | 1998 | 2033 | 6.95% | 110,000 | | 2,562,041 |
| October 1993 | 1998 | 2033 | 6.85% | 108,400 | | 2,670,441 |
| October 1993 | 1998 | 2033 | 6.85% | 50,000 | | 2,720,441 |
| January 1994 | 1999 | 2034 | 7.05% | 50,000 | | 2,770,441 |
| | | | | **$ 2,420,376** | **$ 350,065** | **$ 2,770,441** |
| **Less current portion** | | | | | | (207,300) |
| | | | | | | **$ 2,563,141** |

(a) The weighted average interest rate was 6 percent on outstanding long-term debt as of Sept. 30, 2002. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(b) Corps/Reclamation direct funding.

## 3. 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 Bonneville 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 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 $67.4 million for fiscal 2002 and $68.8 million for 2001, and $67.5 million for 2000. The weighted-average interest rate was 7.0 percent in 2002, and 6.9 percent in 2001 and 7.1 percent in 2000.

Construction and replacement of Corps and Reclamation generating facilities have historically been financed through annual federal appropriations. Annual appropriations were also 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 National Energy Policy Act of 1992 BPA has begun directly funding 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 below shows the term repayments on the remaining federal appropriations as of Sept. 30, 2002.

### Federal Appropriations

*Thousands of dollars*

| Term Repayments | |
|---|---|
| 2003 | $ 46,687 |
| 2004 | 73,484 |
| 2005 | 110,989 |
| 2006 | 68,939 |
| 2007 | 33,694 |
| 2008+ | 4,308,809 |
| **Total** | **$ 4,642,602** |

Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

## 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 has also acquired all of the output of the Cowlitz Falls and Wasco hydro projects. BPA has agreed to fund debt service on Eugene Water and Electric Board, Emerald, 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 reflected in project budgets that are adopted by BPA and the projects' owners.

Operating expense of $175 million in fiscal 2002, $217 million in fiscal 2001 and $174 million in fiscal 2000 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $230 million, $473 million and $561 million for fiscal 2002, 2001 and 2000, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses.

The fair value of all Energy Northwest debt exceeds recorded value by $458 million or 7.6 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2002. All other nonfederal projects' debt approximates fair value as stated.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2002.

### Nonfederal Projects

*Thousands of dollars*

| | Debt Repayments |
|---|---|
| 2003 | $ 243,006 |
| 2004 | 280,350 |
| 2005 | 239,048 |
| 2006 | 267,387 |
| 2007 | 291,865 |
| 2008+ | 4,879,888 |
| **Total** | **$ 6,201,544** |

## 5. Commitments and Contingencies

### 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 $25 million and $17 million for 1997 and 2001 respectively. Future irrigation assistance payments ultimately could total $733 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 table below summarizes future irrigation assistance distributions as of Sept. 30, 2002.

### Irrigation Assistance

*Thousands of dollars*

| | Distributions |
|---|---|
| 2003 | $ — |
| 2004 | 739 |
| 2005 | — |
| 2006 | — |
| 2007 | — |
| 2008+ | 732,195 |
| **Total** | **$ 732,934** |

## 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.

## 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 \$6.2 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is \$12 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is \$4.2 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 \$200 million, BPA could be subject to a retrospective assessment of \$88.1 million limited to an annual maximum of \$10 million.

## Decommissioning and Restoration Costs

In 1999 Energy Northwest successfully transferred assets and site restoration liability for WNP-3 to a consortium of local governments named the Satsop Redevelopment Project. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation Council (EFSEC) that complied with EFSEC's requirement to restore the WNP-1 and WNP-4 sites with minimal hazard to the public. This plan updated Energy Northwest's June 1995 plan. EFSEC's approval recognized that uncertainty still exists as to the exact details of the proposed plan; accordingly, EFSEC's conditional approval provided for additional reviews once the details of the plan are finalized. As part of submitting the restoration plan to EFSEC, Energy Northwest obtained outside estimates for site restoration of WNP-1 and WNP-4. BPA is required to fund site restoration for WNP-1. Funding for WNP-4 is uncertain. The cost of complete site restoration for WNP-1 and WNP-4 is estimated to be up to \$60 million and \$40 million respectively. BPA and Energy Northwest have been negotiating a reduced level of site restoration for WNP-1 as well as WNP-4 with EFSEC and the Department of Energy. A tentative conceptual solution involving a reduced level and delay in accomplishing restoration has been reached and is expected to be recommended for management approval in November. The estimated cost for the recommended level of site restoration at WNP-1 and WNP-4 is about \$25 million and \$23 million (2003 dollars) respectively. BPA believes the existing funds plus earnings will be adequate to cover all site restoration costs.

Decommissioning costs for Columbia Generating Station are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for Columbia Generating Station. The sinking fund is expected to provide for decommissioning at the end of the project's operating life in accordance with Nuclear Regulatory Commission requirements. Sinking fund requirements for Columbia Generating Station are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning sum of expenditures for Columbia Generating Station is \$340 million (1998 dollars). Payments to the sinking fund for the years ended Sept. 30, 2002, 2001 and 2000 were approximately \$4 million per year. The sinking fund balance at Sept. 30, 2002, is \$71 million.

In January 1993, the Portland General Electric 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, 2002, BPA's 30-percent share of this estimated remaining liability is \$74 million which has been recorded net of the decommissioning trust fund balance of \$6 million in the accompanying Balance Sheet. The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements will be greater in the early years of decommissioning and then will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for 2000, 2001 and 2002. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund is being applied directly to the decommissioning expenses. In 2002, the decommissioning trust fund was used to fund a portion of the 2002 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 its share of Trojan's costs through rates and decommissioning trust fund withdrawals. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses.

### 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.

### Endangered Species Act

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

### Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2007.

### 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 and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through 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 sold or purchased.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2002.

### Purchase Power and Sales Commitments

*Thousands of dollars*

| | . Purchase | . Sales |
|---|---|---|
| 2003 | $ 1,046,243 | $ 2,122,146 |
| 2004 | 963,168 | 2,104,685 |
| 2005 | 996,904 | 2,104,686 |
| 2006 | 939,352 | 2,111,821 |
| 2007 | 98,823 | 100,445 |
| 2008+ | 362,570 | 275,043 |
| **Total** | **$ 4,407,060** | **$ 8,818,826** |

Augmentation commitments run through the rate case which ends in 2006.

## 6. 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.

## 7. Segments

In 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 the Bonneville Power Administration has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed in the SFAS 131 Segment Reporting table. Unaffiliated revenues represent sales to external customers for each segment. Intersegment revenues are eliminated.

FCRPS management evaluates the performance of the business lines based on Net Operating Margin (NOM) and does not track the separate balance sheets or net revenues on a business line level. NOM represents revenues generated from operations less operating and maintenance expenses of the segment's revenue-generating assets. On a consolidated basis, this amount represents $994 million for fiscal 2002 ($3,534 million Operating Revenues less $38 million SFAS 133 mark-to-market, $38 million U.S. Treasury Credits for Fish, $1,177 million Operations and Maintenance and $1,287 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

### Major Customers

During fiscal 2002, 2001 and 2000, no single customer represented 10 percent or more of the FCRPS's revenues.

## SFAS 131 Segment Reporting

*For the years ended Sept. 30 — Thousands of dollars*

| | Power | Transmission | Corporate | Total |
|---|---|---|---|---|
| **2002** | | | | |
| Unaffiliated Revenues | $ 2,967,075 | $ 566,654 | $ — | $ 3,533,729 |
| Intersegment Revenues | 80,729 | 153,727 | (234,456) | — |
| Operating Revenues | $ 3,047,804 | $ 720,381 | $ (234,456) | $ 3,533,729 |
| Net Operating Margin | $ 927,061 | $ 355,870 | $ (288,547) | $ 994,384 |
| **2001** | | | | |
| Unaffiliated Revenues | $ 3,824,658 | $ 454,011 | $ — | $ 4,278,669 |
| Intersegment Revenues | 63,394 | 192,662 | (256,056) | — |
| Operating Revenues | $ 3,888,052 | $ 646,673 | $ (256,056) | $ 4,278,669 |
| Net Operating Margin | $ 180,790 | $ 363,822 | $ (161,587) | $ 383,025 |
| **2000** | | | | |
| Unaffiliated Revenues | $ 2,701,373 | $ 365,613 | $ — | $ 3,066,986 |
| Intersegment Revenues | 46,385 | 212,727 | (259,112) | — |
| Operating Revenues | $ 2,747,758 | $ 578,340 | $ (259,112) | $ 3,066,986 |
| Net Operating Margin | $ 1,307,980 | $ 308,188 | $ (123,224) | $ 1,492,944 |

# Schedule of Amount and Allocation of Plant Investment

*Federal Columbia River Power System*
*As of Sept. 30, 2002 — 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 | $ 5,482,014 | $ 5,097,741 | $ 384,273 | $ 5,482,014 | $ — | $ — | $ — |
| Bureau of Reclamation | | | | | | | |
| Boise | 118,268 | 16,576 | 1,263 | 17,839 | 639 | 65,671 | 66,310 |
| Columbia Basin | 1,903,883 | 1,215,976 | 27,777 | 1,243,753 | 493,430 | 143,154 | 636,584 |
| Green Springs | 35,500 | 11,161 | — | 11,161 | 9,934 | 8,070 | 18,004 |
| Hungry Horse | 148,423 | 120,731 | 817 | 121,548 | — | — | — |
| Minidoka-Palisades | 381,854 | 110,381 | 54 | 110,435 | 386 | 72,505 | 72,891 |
| Yakima | 227,818 | 6,160 | 13 | 6,173 | 13,025 | 127,511 | 140,536 |
| **Total Bureau Projects** | 2,815,746 | 1,480,985 | 29,924 | 1,510,909 | 517,414 | 416,911 | 934,325 |
| Corps of Engineers | | | | | | | |
| Albeni Falls | 48,141 | 40,420 | 3,106 | 43,526 | — | — | — |
| Bonneville | 1,371,207 | 873,380 | 93,574 | 966,954 | — | — | — |
| Chief Joseph | 618,659 | 565,479 | 13,006 | 578,485 | — | 163 | 163 |
| Cougar | 93,683 | 20,311 | 31,178 | 51,489 | — | 3,288 | 3,288 |
| Detroit-Big Cliff | 69,365 | 40,998 | 2,241 | 43,239 | — | 5,050 | 5,050 |
| Dworshak | 376,065 | 314,733 | 5,172 | 319,905 | — | — | — |
| Green Peter-Foster | 93,617 | 49,722 | 3,635 | 53,357 | — | 6,210 | 6,210 |
| Hills Creek | 50,242 | 17,665 | 892 | 18,557 | — | 4,616 | 4,616 |
| Ice Harbor | 212,364 | 149,316 | 3,910 | 153,226 | — | — | — |
| John Day | 645,959 | 477,534 | 21,094 | 498,628 | — | — | — |
| Libby | 574,639 | 430,031 | 2,636 | 432,667 | — | — | — |
| Little Goose | 250,475 | 207,582 | 1,431 | 209,013 | — | — | — |
| Lookout Point-Dexter | 107,949 | 49,603 | 6,369 | 55,972 | — | 1,489 | 1,489 |
| Lost Creek | 149,751 | 26,978 | 10 | 26,988 | — | 2,186 | 2,186 |
| Lower Granite | 405,213 | 329,697 | 2,007 | 331,704 | — | — | — |
| Lower Monumental | 268,538 | 224,511 | 1,376 | 225,887 | — | — | — |
| McNary | 366,624 | 284,030 | 8,818 | 292,848 | — | — | — |
| The Dalles | 404,420 | 303,324 | 51,805 | 355,129 | — | — | — |
| Lower Snake | 260,079 | 256,065 | 1,445 | 257,510 | — | — | — |
| Columbia River Fish Bypass | 800,264 | 247,942 | 515,454 | 763,396 | — | — | — |
| **Total Corps Projects** | 7,167,254 | 4,909,321 | 769,159 | 5,678,480 | — | 23,002 | 23,002 |
| AFUDC on Direct Funded Projects | 16,822 | — | 16,822 | 16,822 | — | — | — |
| Irrigation Assistance at 12 Projects having no power generation | 201,179 | — | — | — | 157,144 | 44,035 | 201,179 |
| **Total Plant Investment** | 15,683,015 | 11,488,047 | 1,200,178 | 12,688,225 | 674,558 | 483,948 | 1,158,506 |
| Repayment Obligation Retained by Columbia Basin Project | 4,639 | 2,836 (a) | — | 2,836 (a) | 1,803 | — | 1,803 |
| Investment in Teton Project (b) | 79,107 | — | 7,269 | 7,269 | 56,573 | 3,681 | 60,254 |
| Total | **$15,766,761** | **$11,490,883** | **$1,207,447** | **$12,698,330** | **$732,934** | **$487,629** | **$1,220,563** |

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

(b) 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 | Flood Control | Fish and Wildlife | Recreation | Other | Percent Returnable from Commercial Power Revenues |
| Bonneville Power Administration | | | | | | |
| Transmission Facilities | $ — | $ — | $ — | $ — | $ — | 100.00% |
| Bureau of Reclamation | | | | | | |
| Boise | — | — | — | — | 34,119 | 15.62% |
| Columbia Basin | — | 16,590 | 6,073 | 172 | 711 | 91.24% |
| Green Springs | — | — | — | — | 6,335 | 59.42% |
| Hungry Horse | — | 26,875 | — | — | — | 81.89% |
| Minidoka-Palisades | — | 64,404 | 2,570 | 10,471 | 121,083 | 29.02% |
| Yakima | — | 2,432 | 50,365 | 284 | 28,028 | 8.43% |
| **Total Bureau Projects** | **—** | 110,301 | 59,008 | 10,927 | 190,276 | 72.04% |
| Corps of Engineers | | | | | | |
| Albeni Falls | 180 | 269 | — | 4,166 | — | 90.41% |
| Bonneville | 400,925 | — | — | 1,266 | 2,062 | 70.52% |
| Chief Joseph | — | — | 4,977 | 6,034 | 29,000 | 93.51% |
| Cougar | 548 | 38,358 | — | — | — | 54.96% |
| Detroit-Big Cliff | 219 | 20,857 | — | — | — | 62.34% |
| Dworshak | 9,618 | 31,463 | — | 15,079 | — | 85.07% |
| Green Peter-Foster | 365 | 30,322 | — | 1,693 | 1,670 | 56.99% |
| Hills Creek | 630 | 26,439 | — | — | — | 36.94% |
| Ice Harbor | 55,623 | — | — | 3,515 | — | 72.15% |
| John Day | 90,943 | 18,025 | — | 11,954 | 26,409 | 77.19% |
| Libby | — | 95,141 | 876 | 15,318 | 30,637 | 75.29% |
| Little Goose | 34,739 | — | — | 4,119 | 2,604 | 83.45% |
| Lookout Point-Dexter | 745 | 49,141 | — | 602 | — | 51.85% |
| Lost Creek | — | 53,022 | 24,507 | 29,418 | 13,630 | 18.02% |
| Lower Granite | 52,593 | — | — | 13,074 | 7,842 | 81.86% |
| Lower Monumental | 39,370 | — | — | 2,864 | 417 | 84.12% |
| McNary | 68,856 | — | — | 4,920 | — | 79.88% |
| The Dalles | 47,191 | — | — | 2,078 | 22 | 87.81% |
| Lower Snake | 2,569 | — | — | — | — | 99.01% |
| Columbia River Fish Bypass | 34,230 | 2,638 | — | — | — | 95.39% |
| **Total Corps Projects** | 839,344 | 365,675 | 30,360 | 116,100 | 114,293 | 79.23% |
| AFUDC on Direct Funded Projects | — | — | — | — | — | 100.00% |
| Irrigation Assistance at 12 Projects having no power generation | — | — | — | — | — | 78.11% |
| **Total Plant Investment** | 839,344 | 475,976 | 89,368 | 127,027 | 304,569 | 85.21% |
| Repayment Obligation Retained by Columbia Basin Project | — | — | — | — | — | 100.00% |
| Investment in Teton Project (b) | — | 9,151 | — | 2,433 | — | 80.70% |
| Total | **$839,344** | **$485,127** | **$89,368** | **$129,460** | **$304,569** | **85.2219%** |

QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2003

## Federal Columbia River Power System

**Comparative Balance Sheets (Unaudited)**
(Thousands of Dollars)

| | March 31 2003 | 2002 |
|---|---|---|
| **Assets** | | |
| **Utility Plant** | | |
| Completed plant | **$11,576,469** | $11,323,659 |
| Accumulated depreciation | **(4,174,785)** | (3,940,073) |
| | **7,401,684** | 7,383,586 |
| Construction work in progress | **1,290,326** | 996,716 |
| Net utility plant | **8,692,010** | 8,380,302 |
| **Nonfederal Projects** | **6,204,572** | 6,176,059 |
| **Trojan Decommissioning Cost** | **73,726** | 66,710 |
| **Conservation, net of accumulated amortization** | **391,701** | 413,710 |
| **Fish & Wildlife, net of accumulated amortization** | **126,475** | 141,426 |
| **Current Assets** | **1,092,407** | 1,307,215 |
| **Other Assets** | **143,375** | 201,819 |
| | **$16,724,266** | $16,687,241 |
| **Capitalization and Liabilities** | | |
| **Accumulated Net Expenses** | **($1,906)** | ($284,626) |
| **Federal Appropriations** | **4,596,506** | 4,671,085 |
| **Capitalization Adjustment** | **2,158,548** | 2,226,078 |
| **Long-Term Debt** | **2,663,141** | 2,622,542 |
| **Nonfederal Projects Debt** | **5,961,206** | 5,958,230 |
| **Trojan Decommissioning Reserve** | **63,726** | 54,710 |
| **Current Liabilities** | **801,497** | 869,715 |
| **Deferred Credits** | **481,548** | 569,507 |
| | **$16,724,266** | $16,687,241 |

The irrigation assistance distribution of $16,560 for fiscal 2001 is included in accumulated net expenses.

**Comparative Statements of Revenues and Expenses (Unaudited)**
(Thousands of Dollars)

| | Six months ended March 31 | | Twelve months ended March 31 | |
|---|---|---|---|---|
| | **2003** | 2002 | **2003** | 2002 |
| **Operating Revenues:** | | | | |
| Revenues | **$1,712,807** | $1,726,629 | **$3,393,582** | $3,304,467 |
| SFAS 133 mark-to-market (loss) gain | **21,230** | 1,319 | **58,265** | (3,119) |
| Other revenues | **20,789** | 17,191 | **53,169** | 50,347 |
| U.S. Treasury credits for fish | **66,264** | 26,158 | **78,506** | 534,649 |
| **Operating Revenues** | **1,821,090** | 1,771,297 | **3,583,522** | 3,886,344 |
| **Operating Expenses:** | | | | |
| Operations and maintenance | **567,490** | 577,068 | **1,310,129** | 1,150,221 |
| Purchased power | **584,260** | 738,704 | **1,132,423** | 1,896,945 |
| Non-Federal projects | **112,993** | 170,762 | **172,406** | 325,623 |
| Federal projects depreciation | **173,721** | 160,923 | **348,003** | 324,769 |
| **Operating Expenses** | **1,438,464** | 1,647,457 | **2,962,961** | 3,697,558 |
| Net operating revenues (expenses) | **382,626** | 123,840 | **620,561** | 188,786 |
| **Interest Expense** | **172,856** | 187,315 | **337,841** | 354,924 |
| **Net (Expenses) Revenues** | **$209,770** | ($63,475) | **$282,720** | ($166,138) |

**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.

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## APPENDIX B

## SUMMARY OF THE BOND RESOLUTION

The following summary is an outline of certain provisions of the Bond Resolution, is not to be considered a full statement hereof and is qualified by reference to the complete Bond Resolution.

**Certain Definitions Used in the Bond Resolution**

"Accreted Value" means with respect to any Capital Appreciation Bonds (a) as of any Valuation Date, the amount set forth for such date in any Supplemental Resolution authorizing such Capital Appreciation Bonds and (b) as of any date other than a Valuation Date, the sum of (i) the Accreted Value on the preceding Valuation Date and (ii) the product of (1) a fraction, the numerator of which is the number of days having elapsed from the preceding Valuation Date and the denominator of which is the number of days from such preceding Valuation Date to the next succeeding Valuation Date, calculated based on the assumption that Accreted Value accrues during any semiannual period in equal daily amounts on the basis of a year of 12 30-day months, times (2) the difference between the Accreted Values for such Valuation Dates.

"Annual Debt Service" for any Fiscal Year means the sum of the amounts required to be paid in such Fiscal Year to pay:

(a) the interest due in such Fiscal Year on all outstanding Bonds, excluding interest to be paid from the proceeds of sale of Bonds or other debt; and

(b) the principal of all outstanding Serial Bonds due in such Fiscal Year, including the Sinking Fund Requirement, if any, for such Fiscal Year; and

(c) amounts required to pay premiums for redeeming Bonds prior to their scheduled maturity; and

(d) any regularly scheduled Payments, adjusted by any regularly Reciprocal Payments, during such Fiscal Year.

For purposes of this definition, the principal and interest portions of the Accreted Value of Capital Appreciation Bonds and the Appreciated Value of Deferred Income Bonds becoming due at maturity or by virtue of a Sinking Fund Requirement shall be included in the calculations of accrued and unpaid and accruing interest or principal in such manner and during such period of time as is specified in any Supplemental Resolution authorizing such Capital Appreciation Bonds or Deferred Income Bonds. For the purpose of calculating the principal and interest on Tender Option Bonds in any Fiscal Year, such Bonds shall be assumed to mature on the stated maturity date or, in the case of Term Bonds, on the mandatory redemption date, if any, thereof.

"Appreciated Value" means with respect to any Deferred Income Bonds, (A) (1) as of any Valuation Date, the amount set forth for such date in any Supplemental Resolution authorizing such Deferred Income Bonds and (2) as of any date other than a Valuation Date, the sum of (a) the Appreciated Value on the preceding Valuation Date and (b) the product of (i) a fraction, the numerator of which is the number of days having elapsed from the preceding Valuation Date and the denominator of which is the number of days from such preceding Valuation Date to the next succeeding Valuation Date calculated based on the assumption that Appreciated Value accrues during any semiannual period in equal daily amounts on the basis of a year of 12 30-day months, times (ii) the difference between the Appreciated Values for such Valuation Dates, and (B) as of any date of computation on and after the Interest Commencement Date, the Appreciated Value on the Interest Commencement Date.

"Authorized Officer" when used with reference to the District means the President, Vice President or Secretary of the Board, the Manager of the District or such other officer designated by resolution of the Board.

"Board" means the Board of Commissioners of the District, as duly and regularly constituted from time to time.

"Bonneville" means the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration.

"Bonneville Agreements" means the Power Purchase Contract and the Payment Agreement.

"Capital Appreciation Bonds" means any Bonds hereafter issued as to which interest is payable only at the maturity or prior redemption of such Bonds. For the purposes of (i) receiving payment of the redemption price, if any, of a Capital Appreciation Bond that is redeemed prior to maturity, or (ii) computing the principal amount of Bonds held by the owner of a Capital Appreciation Bond in giving to the District or the Paying Agent any notice, consent, request, or demand pursuant to the Bond Resolution for any purpose, the principal amount of a Capital Appreciation Bond shall be deemed to be its Accreted Value.

"Certified Public Accountant" means an independent certified public accountant (or firm of certified public accountants) selected by the District and having a favorable national reputation.

"Closing" means the delivery of any Bonds to, and payment of the purchase price therefor by, the initial purchasers of any Bonds.

"Code" means the Internal Revenue Code of 1986, as amended, together with corresponding and applicable final, temporary or proposed regulations and revenue rulings issued or amended with respect thereto by the United States Treasury Department of the Internal Revenue Service, to the extent applicable to the Bonds.

"Commission" means the Securities and Exchange Commission.

"Cowlitz Falls Bonds" or "Bonds" means the Cowlitz Falls Project Revenue Bonds of the District authorized to be issued pursuant to the Bond Resolution.

"Cowlitz Falls Project" or "Project" means the separate system of the District as described in FERC License No. 2833, including amendments and revisions now or hereafter approved by FERC, consisting of the electric utility properties and assets, real and personal, tangible and intangible, of the Cowlitz Falls Hydroelectric Project of the District, as created by the Original Resolution, including a dam, spillway, powerhouse, reservoir, transmission and electrical facilities, operations and maintenance facilities, land, and the facilities and programs for wildlife, recreation, debris and sediment control, and other mitigation, and all additions, betterments, renewals, replacements and repairs, improvements to and extensions of such Project, but shall not include the Electric System (including the transmission line from the Glenoma substation to the Mossyrock switchyard) or any other properties, rights or assets, real or personal, tangible or intangible, that hereafter may be purchased, constructed or otherwise acquired by the District as a system that is declared by the Board at the time of financing thereof to be separate from the Cowlitz Falls Project, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire or expand such separate system or otherwise may be pledged to the payment of the bonds of another such separate system of the District.

"Cowlitz Falls Project Power Costs" or "Project Power Costs" means with respect to each month an amount equal to all costs attributable to the Cowlitz Falls Project, to the extent not payable from the proceeds of Bonds or other sources (including income and investment of such proceeds), resulting from the ownership, operation, maintenance of, and repairs, renewals, replacements, additions, improvements, betterments and modifications of the Cowlitz Falls Project, including, without limitation, the following items of cost:

(a) O & M Costs;

(b) Other Renewals and Replacements Costs;

(c) An amount equal to the sum of the following:

(i) All amounts required to be paid into the Interest Account, and the Serial Bond Principal and Term Bond Principal Accounts and amounts, if any, required to be paid into the Reserve Account in the Bond Fund during such month;

(ii) Any amount the District may be required during such month to deposit into any Junior Lien Fund or Account;

(iii) Any amount required to be paid or deposited during such month into the Reserve and Contingency Account in the Revenue Fund or any other fund or account under the Bond Resolution;

(iv) Any amount that the District may be required during such month to pay for the prevention or correction of any unusual loss or damage or for renewals, replacements, repairs, additions, improvements, betterments, and extensions that are necessary or prudent to keep the Cowlitz Falls Project in good operating condition, to improve the operation thereof or to prevent a loss of Cowlitz Falls Revenues therefrom, but in each case only to the extent that funds for such payment are not available to the District from any funds or accounts established under the Bond Resolution for such purposes or funds for such payment are not provided by the issuance of Bonds or other obligations of the District; and

(v) All other charges or obligations of the Project against the Cowlitz Falls Revenues of whatever nature and whether now or hereafter imposed by the Bond Resolution, by law or by contract.

"Cowlitz Falls Revenues" or "Revenues" means all income, revenues, receipts and payments derived by the District in connection with the Cowlitz Falls Project, including with respect to Bonds the debt service of which is to be paid in part or in whole by Bonneville under the Bonneville Agreements, payments received pursuant to the Power Purchase Contract, and including with respect to all Bonds the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Cowlitz Falls Project and together with the investment income earned on moneys held in any fund or account of the District, including any bond redemption funds and the accounts therein, in connection with the Cowlitz Falls Project, exclusive of insurance proceeds and income derived from investments irrevocably pledged to the defeasance of any specific revenue bonds of the District, such as bonds heretofore or hereafter refunded, or any Bonds defeased pursuant to the Bond Resolution or other bonds defeased, or the payment of which is provided for, under any similar provision of any other bond resolution of the District, and exclusive of payments under the Payment Agreement and moneys in any fund or account hereafter created for the purpose of complying with the rebate provisions of Section 148 of the Code. "Cowlitz Falls Revenues" shall not include any income derived by the District through the ownership and operation of the Electric System or any other generation, transmission or distribution facilities that may hereafter be purchased, constructed or otherwise acquired by the District as a separate system.

"Deferred Income Bonds" means any Cowlitz Falls Bonds issued under any Supplemental Resolution as to which accruing interest is not paid prior to the Interest Commencement Date specified in such resolution and the Appreciated Value for such Bonds is compounded semiannually on the Valuation Date for such Deferred Income Bonds.

"Derivative Facility" means a letter of credit, an insurance policy, a surety bond or other credit enhancement device, given, issued or posted as security for the District's obligations under one or more Derivative Products.

"Derivative Payment Date" means any date specified in the Derivative Product on which a District Payment is due and payable under the Derivative Product.

"Derivative Product" means a written contract or agreement between the District and a third party that has (or whose obligations are unconditionally guaranteed by a party that has) as of the date of the Derivative Product at least an investment grade rating from a rating agency (the "Reciprocal Payor"), which provides that the District's obligations thereunder will be conditioned on the performance by the Reciprocal Payor of its obligations under the agreement; and

(1) under which the District is obligated to pay, on one or more scheduled and specified Derivative Payment Dates, the District Payments in exchange for the Reciprocal Payor's obligation to pay or to cause to be paid to the District, on scheduled and specified Derivative Payment Dates, the Reciprocal Payments;

(2) for which the District's obligations to make the District Payments may be secured by a pledge of and lien on Cowlitz Falls Revenues on an equal and ratable basis with the outstanding Bonds;

(3) under which Reciprocal Payments are to be made directly into the Bond Fund;

(4) for which the District Payments are either specified to be one or more fixed amounts or are determined as provided by the Derivative Product; and

(5) for which the Reciprocal Payments are either specified to be one or more fixed amounts or are determined as set forth in the Derivative Product.

"District Payment" means any payment designated as such by resolution and required to be made by or on behalf of the District under a Derivative Product and which is determined according to a formula set forth in the Derivative Product.

"DTC" means The Depository Trust Company of New York, as depository for the 2003 Bonds, or any successor or substitute depository for the 2003 Bonds.

"Electric System" means the electric utility properties, rights and assets, real and personal, tangible and intangible, now owned and operated by the District and used or useful in the generation, transmission, distribution and sale of electric energy and the business incidental thereto, and all properties, rights and assets, real and personal, tangible and intangible, hereafter constructed or acquired by the District as additions, betterments, improvements or extensions to said electric utility properties, rights and assets, but shall not include the Cowlitz Falls Project or any other generating, transmission and distribution facilities which hereafter may be acquired or constructed by the District as a utility system that is declared by the Board, at the time of financing thereof, to be separate from the Electric System, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire or expand such separate utility system or are otherwise pledged to the payment of the bonds of another such separate utility system of the District other than the Electric System. The Board may, by resolution, elect to combine with and include as a part of the Electric System any other separate utility system of the District, provided that full provision for the payment of any outstanding indebtedness of such separate system shall first be made or such indebtedness shall be refunded or the combined system complies with all covenants of all bond resolutions of the Electric System and such separate system.

"Electric System Bonds" means all bonds issued by the Electric System and which are secured by Electric System Revenues.

"Electric System Operating Expenses" means the District's expenses for operation of the Electric System and routine repairs, renewals, and replacements of the Electric System as more specifically defined in any Electric System resolution, exclusive of the expenses for operation and repairs, renewals and replacements of the Cowlitz Falls Project.

"Electric System Revenues" means income, receipts and revenues received by the District from the sale of electric energy through the ownership or operation of the Electric System and all other commodities, services and facilities sold, furnished or supplied by the District through the ownership or operation of the Electric System, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Electric System, and together with the investment income earned on money held in any fund or account of the District, including any bond redemption funds and the accounts therein, in connection with the ownership and operation of the Electric System (but exclusive of income derived from investments irrevocably pledged to the payment of any specific revenue bonds of the District, such as bonds heretofore or hereafter refunded, or any Electric System Bonds defeased).

"FERC License" means the license (FERC License No. 2833) issued by the Federal Energy Regulatory Commission (FERC), or its successor, to the District on June 30, 1986, and any extensions, renewals, and amendments thereof, which permits the District to construct and operate the Cowlitz Falls Project.

"FERC Uniform System of Accounts" means the system of accounts prescribed by the Federal Energy Regulatory Commission (or its successor in function) for public utilities and licensees, as the same may be amended, at 18 C.F.R. 101, et seq.

"Fiscal Year" means the Fiscal Year used by the District at any time. At the time of the adoption of this Resolution, the Fiscal Year is the 12-month period beginning January 1 of each year.

"Government Obligations" means those obligations as defined in RCW 39.53, as amended.

"Interest Commencement Date" means, with respect to any particular Deferred Income Bonds, the date specified in any Supplemental Resolution authorizing such Bonds (which date must be prior to the maturity date for such Bonds) after which interest accruing on such Bonds shall be payable periodically, with the first such payment date being the applicable interest payment date immediately succeeding such Interest Commencement Date.

"Junior Lien Fund or Account" means any special fund or account created to pay or secure the payment of the principal of and interest on any revenue bonds, warrants or other revenue obligations of the District having a lien upon Cowlitz Falls Revenues and money in the Revenue Fund and accounts therein junior and inferior to the lien thereon for the payment of the principal of and interest on the Bonds, exclusive of funds set aside for the defeasance of any such junior lien obligations.

"Letter of Representations" means the Blanket Letter of Representations from the District to The Depository Trust Company.

"Maximum Interest Rate" means, with respect to any particular Variable Interest Rate Bond, a numerical rate of interest, which shall be set forth in any Supplemental Resolution authorizing such Bond, that shall be the maximum rate of interest such Bond may at any time bear.

"Operating Year" means any consecutive 12-month period during the Term of the Bonneville Agreements which commences at 2400 hours, September 30, and ends at 2400 hours the following September 30.

"Operation and Maintenance Costs" or "O & M Costs" means those expenses for operation and maintenance of the Cowlitz Falls Project and routine repairs, renewals of and replacements to the Cowlitz Falls Project, including payments into working capital reserves in the Revenue Fund for items of O & M Costs the payment of which is not immediately required, and shall include, without limiting the generality of the foregoing, operation and maintenance expenses; rents; costs of spare parts; recreation and Cowlitz Falls Project mitigation costs that are not capitalized; administrative and general expenses and insurance costs allocable to the Cowlitz Falls Project; transmission wheeling costs incurred to integrate Project output; engineering expenses; legal fees, Trustee fees, Paying Agent fees, Registrar fees, letter of credit fees, and financial advisor expenses; labor costs and associated taxes and benefits; insurance premiums; any amounts required to be rebated to the federal government pursuant to Section 148 of the Code; and any taxes, assessments, payments in lieu of taxes or other lawful governmental charges, all to the extent properly allocable to the Cowlitz Falls Project under generally accepted accounting principles. Operation and Maintenance Costs shall not include any costs or expenses for new construction that is capitalized, interest, amortization or any allowance for depreciation. During the Term of the Bonneville Agreements, no cost shall be recognized as an O & M Cost which is not or would not be an O & M Cost under the Power Purchase Contract.

"Original Resolution" means Resolution No. 1847 of the District.

"Other Renewals and Replacements" means actions or items which are not included in O & M Costs that are required by the Cowlitz Falls Project to repair loss or damage, make repairs, renewals and replacements, make additions, betterments, improvements and extensions, comply with regulatory requirements, and to keep the Cowlitz Falls Project in good operating condition.

"Other Renewal and Replacement Costs" means costs incurred for any Other Renewals and Replacements for the Project.

"Outstanding" means Cowlitz Falls Bonds the principal of and interest on which has not been paid under this Resolution and which have not been defeased pursuant to the Bond Resolution.

"Paying Agent" initially means the Trustee, and the designated fiscal agencies of the State of Washington or any bank or banks subsequently designated a paying agent by the District.

"Payment Agreement" means the Payment Agreement between Bonneville and U.S. Bank, National Association, as Trustee.

"Permitted Investments" means any investments or investment agreements which the District is permitted to make under the laws of the State of Washington, as amended from time to time.

"Power Purchase Contract" means the contract executed January 28, 1991 and restated as of May 23, 1991 between the District and Bonneville pursuant to which the District has agreed to sell and Bonneville has agreed to purchase the output of the Cowlitz Falls Project and Bonneville has agreed to pay Cowlitz Falls Project Power Costs.

"Qualified Insurance" means any municipal bond insurance policy or surety bond issued by any insurance company licensed to conduct an insurance business in any state of the United States (or by a service corporation acting on behalf of one or more such insurance companies) which insurance company or companies, as of the time of issuance of such policy or surety bond, are rated in one of the two highest rating categories by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc.or their comparably recognized business successors, or in the event each of such rating agencies rates such institution, by each of them.

"Qualified Letter of Credit" means any letter of credit issued by a bank or financial institution for the account of the District on behalf of the owners of the Bonds or any series of Bonds, which bank or other financial institution issuing the letter of credit maintains an office, agency or branch in the United States and as of the time of issuance of such letter of credit is currently rated in one of the three highest rating categories by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc. or their comparably recognized business successors, or in the event each of such rating agencies rates such institution, by each of them.

"Reciprocal Payment" means any payment, designated as such by resolution, to be made to, or for the benefit of, the District under a Derivative Product by the Reciprocal Payor.

"Reciprocal Payor" means a party to a Derivative Product that is obligated to make one or more Reciprocal Payments thereunder.

"Record Date" for any series of Bonds means the record date or dates established in the Supplemental Resolution providing for the issuance of such series of Bonds.

"Refunded Municipals" means pre-refunded municipal obligations meeting the following conditions: (i) the obligations are not callable prior to maturity or the Trustee has been given irrevocable instructions concerning their call and redemption and the issuer has covenanted not to redeem such bonds other than as set forth in such instructions; (ii) the obligations are secured by cash or Governmental Obligations which may be applied only to interest, principal, and premium payments of such obligations; (iii) the obligations are rated in the highest rating category by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc., or in the event each of such rating agencies has rated such obligations, by each of them; (iv) the principal and interest of the Governmental Obligations (plus any cash securing such obligations) are sufficient to meet the liabilities of the obligations, which sufficiency has been verified by a Certified Public Accountant; (v) the Government Obligations serving as security for the obligations are held by an escrow agent or a Trustee; and (vi) the Government Obligations are not available to satisfy any other claims, including those against the trustee or escrow agent.

"Refunding Bonds" means Bonds issued for the purpose of refunding Bonds of any prior series of Bonds or for satisfying any reimbursement obligation made pursuant to the Bond Resolution.

"Registered Owner" means the person in whose name a 2003 Bond is registered on the Bond Register. For so long as the District utilizes the book-entry system for the 2003 Bonds, DTC shall be deemed to be the Registered Owner.

"Registrar" means the registrar and authenticating agent appointed pursuant to the Bond Resolution, its successor or successors and any other entity that may at any time be substituted in its place pursuant to this Resolution.

"Reserve Account Requirement" means for each series of Bonds an amount, if any, determined when each series of Bonds is issued. For all Bonds outstanding, the Reserve Account Requirement is the sum of the Reserve Account Requirements for all series of Bonds; provided, that the Reserve Account Requirement for the 2003 Bonds shall be zero.

"Serial Bonds" means Bonds falling due by their terms in specified years for which no mandatory sinking fund payments are required.

"Sinking Fund Requirement" means, for any Fiscal Year, the principal amount and premium, if any, of Term Bonds required to be purchased, redeemed or paid at maturity or paid into any sinking fund account for such Fiscal Year as established by the Supplemental Resolution authorizing the issuance of such Term Bonds.

"Supplemental Resolution" means any resolution adopted by the Board pursuant to and in compliance with the provisions of the Bond Resolution providing for the issuance of Bonds, and shall also mean any other resolution adopted by the Board pursuant to and in compliance with the provisions of the Bond Resolution amending or supplementing the provisions of the Bond Resolution as originally adopted or as theretofore amended or supplemented.

"Tender Option Bonds" means Cowlitz Falls Bonds that the owner may at its option, or is required to, demand payment of the principal and accrued interest thereof or the purchase of such Bonds by or on behalf of the District in advance of the otherwise scheduled dates for the payment of principal and interest thereon.

"Term Bonds" means Bonds of any principal maturity that are subject to mandatory redemption or for which mandatory sinking fund payments are required.

"Term of the Bonneville Agreements" means the later of the end of the term of the Power Purchase Contract or the Payment Agreement.

"Treasurer" means the Treasurer of the District as designated, from time to time, by resolution of the Board.

"Valuation Date" means (i) with respect to any Capital Appreciation Bonds the date or dates set forth in any Supplemental Resolution authorizing such Bonds on which specific Accreted Values are assigned to the Capital Appreciation Bonds, and (ii) with respect to any Deferred Income Bonds the date or dates prior to the Interest Commencement Date set forth in any Supplemental Resolution authorizing such Bonds on which specific Appreciated Values are assigned to the Deferred Income Bonds.

"Variable Interest Rate" means a variable interest rate or rates to be borne by a series of Cowlitz Falls Bonds or any one or more maturities within a series of Cowlitz Falls Bonds. The method of computing such variable interest rate shall be specified in the Supplemental Resolution authorizing such series of Bonds. Such variable interest rate shall be subject to a Maximum Interest Rate and there may be an initial rate specified, in each case as provided in such Supplemental Resolution, or a stated interest rate that may be changed from time to time as provided in the Supplemental Resolution. Such Supplemental Resolution shall also specify either (i) the particular period or periods of time or manner of determining such period or periods of time for which each such variable interest rate shall remain in effect or (ii) the time or times upon which any change in such variable interest rate shall become effective and shall specify the frequency and method of payment of Variable Interest Rate Bonds.

"Variable Interest Rate Bonds" for any period of time means Cowlitz Falls Bonds which during such period bear a Variable Interest Rate, provided that Bonds the interest rate on which shall have been fixed for the remainder of the term thereof shall no longer be Variable Interest Rate Bonds.

**Funds and Accounts**

1. Revenue Fund. The District has pledged to pay all Cowlitz Falls Revenues into the Revenue Fund except as specifically provided in the Bond Resolution. The Revenue Fund consists of the General Account and the Reserve and Contingency Account. The Cowlitz Falls Revenues paid into the Revenue Fund shall first be credited to the General Account. The Cowlitz Falls Revenues in the Revenue Fund and the Bond Fund shall be applied as specified under "SECURITY FOR THE 2003 BONDS—Flow of Funds" in this Official Statement.

There shall be deposited into the Reserve and Contingency Account such funds as the Board deems appropriate to make up any deficiencies in the Reserve Account and the Bond Fund and for other costs of the Project.

2. Bond Fund. Bonneville has agreed in the Bonneville Agreements to make payments directly to the Trustee for deposit as follows:

(a) Into the Interest Account, on or prior to each interest payment date, the amount equal to the installment of interest next falling due on all Bonds.

(b) Into the Serial Bond Principal Account, on or prior to each date upon which an installment of principal on Serial Bonds falls due, the amount equal to the installment of principal next falling due on the Serial Bonds.

(c) Into the Term Bond Principal Account, on or prior to each date on which a Sinking Fund Requirement falls due, the amount equal to the Sinking Fund Requirements next falling due on all Term Bonds.

Money in the Bond Fund shall be invested in Permitted Investments.

3. Reserve Account. The Reserve Account is established as a separate account in the Bond Fund in order to provide a reserve for the principal, premium, if any, and interest on the Bonds. A separate Reserve Account may be established for a series of Bonds. There is no Reserve Account funding requirement for the 2003 Bonds.

**Additional Bonds and Derivative Products**

1. Bonds. Additional bonds may be issued upon the conditions set forth under the heading "SECURITY FOR THE 2003 BONDS—Additional Bonds."

The District may contract with any entity providing a Qualified Letter of Credit or Qualified Insurance for the Reserve Account that the District's reimbursement obligation to such entity ranks on a parity of lien with the 2003 Bonds, but only if, for as long as any 2003 Bonds remain outstanding, the Power Purchase Contract treats any such obligation as a Project Power Cost or if such reimbursement obligation is payable under the Payment Agreement.

2. Junior Lien Bonds. The District may issue bonds, notes, certificates or other evidences of indebtedness relating to the Project payable from Cowlitz Falls Revenues subordinate to the payments required to be made from the Revenue Fund into the Bond Fund for the 2003 Bonds.

3. Electric System and Other System Bonds. The District may issue bonds payable from Electric System Revenues. The District also may issue bonds payable from revenues of any other separate system.

4. Derivative Products. The District may enter into a Derivative Product on a parity with the Bonds as long as the Derivative Product satisfies the requirements for Additional Bonds described under the heading "SECURITY FOR THE 2003 BONDS—Additional Bonds."

**Defeasance of Bonds**

The District may or, during the term of the Power Purchase Agreement upon the direction of Bonneville and the provision of sufficient funds or securities as described in the Bond Resolution by Bonneville, shall set aside, together with other moneys legally available therefor, with a trustee or escrow agent in a special account pledged to the payment of all or a portion of the 2003 Bonds, cash, non-callable Government Obligations and/or Refunded Municipals, if permitted by law, sufficient in amount, together with the earnings thereon, to provide funds to pay when due the interest on such 2003 Bonds and to redeem or retire such Bonds at or prior to maturity (as determined by the District) in accordance with their terms. In such event no further payment need be made into the Bond Fund for the payment of the principal of, premium, if any, and interest on the 2003 Bonds so provided for and such Bonds shall cease to be entitled to any lien, benefit or security of the Bond Resolution except the right to receive payment from such special account, and such Bonds shall not be deemed to be outstanding for any purpose of the Bond Resolution or the Supplemental Resolution authorizing their issuance. The District shall obtain an opinion of Bond Counsel to the effect set forth in the preceding sentence and that the status of such Bonds and any other outstanding Bonds is not adversely affected under the Code. Notwithstanding the defeasance of any Bonds pursuant to the Bond Resolution, the District shall remain obligated to make any payments with respect to such Bonds required to be made to the United States by Section 148 of the Code. Within 30 days following the defeasance of any 2003 Bonds pursuant to the Bond Resolution, the District shall mail written notice of the action so taken to the owners of the defeased Bonds''.

**Covenants**

In the Bond Resolution the District has agreed to various covenants, including the following:

1. To Maintain the Properties of the Cowlitz Falls Project and to Keep the Cowlitz Falls Project in Good Repair. The District will, consistent with the Power Purchase Contract for the Term of the Bonneville Agreements, (a) at all times operate (unless the District is replaced as operator pursuant to the Power Purchase Contract) the properties of the Cowlitz Falls Project, including necessary transmission facilities, and the business in connection therewith in an efficient manner and at reasonable cost, (b) maintain or cause to be maintained the properties of the Cowlitz Falls Project, including necessary transmission facilities, and all improvements thereto and extensions thereof, in reasonably good repair, working order and condition, and (c) make, or cause to be made, all necessary repairs, renewals, replacements, additions, improvements and betterments thereto and extensions thereof, so that at all times the business carried on in connection therewith shall be properly and advantageously conducted.

The District will use its best efforts to comply with the terms of any permit or license for the Cowlitz Falls Project and with any federal, state or local regulation applicable to the Project, including without limitation, the FERC License.

2. Rates and Charges of the Cowlitz Falls Project. The District will establish and collect rates and charges for electric power and energy or other goods and services sold or supplied through the Cowlitz Falls Project that will be sufficient to provide the District with Cowlitz Falls Revenues sufficient for the payment of Cowlitz Falls Project Power Costs, after crediting against such costs amounts paid from the Reserve and Contingency Account or from insurance proceeds.

3. Disposition of All or Part of the Cowlitz Falls Project. Except as provided in the Power Purchase Contract, the District will not sell, mortgage, lease or otherwise dispose of or encumber all or any portion of the Cowlitz Falls Project except:

(a) The District may dispose of all or substantially all of the Cowlitz Falls Project, provided that simultaneously the District shall cause all of the Bonds to be, or deemed to be, no longer outstanding. The District may not sell or otherwise dispose of any part of the useful operating properties of the Cowlitz Falls Project if such sale or disposition would result in a reduction of Cowlitz Falls Revenues below that required to be maintained under paragraph 2 above.

(b) The District may dispose of, consistent with the terms of the Power Purchase Contract, any portion of the Cowlitz Falls Project that the Board determines to be unserviceable, inadequate, obsolete, worn out or unfit to be used or no longer required for use in connection with the operation of the Cowlitz Falls Project whether due to delay or termination of Project construction or operation. Moneys received by the District as the proceeds of any such sale, lease or other disposition shall be transferred to the Reserve Account to the extent that such transfer shall be necessary to make up any deficiency in the Reserve Account and the balance, if any, shall either (i) be used for repairs, renewals, replacements, or additions to or extensions of the Cowlitz Falls Project or (ii) be used in the retirement of a prorated portion of all outstanding Bonds as specified in the Bond Resolution.

(c) If the ownership of all or part of the Project is transferred from the District through the operation of law, including condemnation, the District shall reconstruct or replace the portion unless the Board determines that such reconstruction or replacement is not in the best interests of the District and the bondowners, in which case any proceeds shall be used to retire Bonds prior to maturity.

4. Insurance. Subject to the terms of the Power Purchase Contract during the Term of the Bonneville Agreements, the District will either insure or self-insure the Project against risks, accidents or casualties, at least to the extent that insurance is usually carried by municipal corporations operating like properties and if such insurance is available at a reasonable cost. In the event of any loss or damage, and subject to the terms of the Power Purchase Contract during the Term of the Bonneville Agreements, the District will promptly deposit the insurance proceeds received from insurance for the Project into any construction fund hereafter created, and use such funds to repair or replace the damaged portion of the insured property or transfer the proceeds of such insurance or self-insurance funding to the Reserve Account to the extent that such transfer shall be necessary to make up any deficiency in the Reserve Account and the balance, if any, shall either (i) be used for repairs, renewals, replacements, or additions to or extensions of the Cowlitz Falls Project or (ii) be used in the retirement of Bonds prior to maturity, either by purchase at prices not to exceed the next applicable redemption price or by call for redemption.

5. Books of Account. The District shall keep proper books of account, which will be audited annually by the Washington State Auditor's office or an independent public accountant. Any bondowner may obtain at the office of the District or upon written request to the District copies of the District's annual report.

6. Protection of Security. The District shall comply with the terms of the Power Purchase Contract so long as such contract is in effect. Nothing in the Bonneville Agreements shall be amended, modified, or otherwise altered in any manner which will reduce the payments pledged as security for the Bonds or extend the time of such payments provided in the Power Purchase Contract or which will in any manner materially impair or adversely affect the rights of the owners of the Bonds.

7. Tax Covenants. The District will not take any action that will cause the 2003 Bonds to be "arbitrage bonds" under the Code.

**Trustee**

U.S. Bank National Association, Portland, Oregon, is appointed to act as Trustee for the owners of all Bonds. The Trustee may resign upon 45 days' notice mailed to each bondowner or published in a newspaper of general circulation or financial journal published in New York. Such resignation shall take effect upon the appointment of a new Trustee. The Trustee may be discharged by the District as long as an Event of Default has not occurred and is continuing or by the owners of a majority of the outstanding Bonds. The consent of Bonneville shall be required for any such discharge. If the Trustee resigns or is discharged the District shall appoint a new Trustee. At any time within one year after such appointment, the Owners of a majority of the outstanding Bonds may appoint a successor Trustee, which shall supersede any Trustee appointed by the District.

Prior to the occurrence of an Event of Default and subsequent to the curing of such Event of Default, the Trustee shall not be liable except for the performance of its duties and obligations set forth in the Bond Resolution and to act in good faith in the performance thereof, and no implied duties or obligations shall be incurred by the Trustee other than those specified in the Bond Resolution. If an Event of Default has occurred and not been cured, the Trustee shall use the same degree of care and skill in the exercise of its duties set forth in the Bond Resolution as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. The Trustee shall not be deemed to have knowledge of any Event of Default not known to the Trustee.

The Trustee is not responsible for the recitals of fact in the Bond Resolution and makes no representations as to the legal validity or sufficiency of the Bond Resolution or of any Bonds or in respect of the security afforded by the Bond Resolution.

Any money deposited with the Paying Agent and not applied to the payment of Bonds within three years following the final maturity or redemption of the Bonds shall be transferred to the District free from the trusts created by the Bond Resolution.

**Events of Default and Remedies**

1. Events of Default. The following constitute "Events of Default" under the Bond Resolution:

(a) Default in the punctual payment of the principal of any Bond when the same shall become due;

(b) Default in the punctual payment of interest on any Bond when the same shall become due;

(c) Failure to purchase or redeem Term Bonds in a principal amount at least equal to the applicable Sinking Fund Requirement when the same shall become due;

(d) Default under any agreement with respect to a Qualified Letter of Credit or Qualified Insurance or other credit enhancement device providing security for the Bonds, which results in suspension, expiration or termination of the payment obligations of the issuer of the device and the District within ten days of such suspension, expiration or termination of payment obligations fails to obtain a substitute credit enhancement device or take other measures to remedy such default;

(e) Default in the observance of any other of the covenants and conditions in the Bond Resolution and such default continues for 90 days after the District receives from the Trustee or from the owners of not less than 66% in principal amount of any series of Bonds outstanding a written notice specifying and demanding the cure of such default; or

(f) If the District shall admit in writing its inability to pay its debts as they become due, file a petition in bankruptcy, make an assignment for the benefit of its creditors, consent to the appointment of a receiver for the Cowlitz Falls Project; or consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of the District or of the whole or any substantial part of the Cowlitz Falls Project.

2. Payment of Funds to Trustee. If an Event of Default is not remedied, the District, upon demand of the Trustee, shall pay to the Trustee all funds held by the District and pledged under the Bond Resolution and Cowlitz Falls Revenues upon receipt. The Trustee shall apply the funds in accordance with the Bond Resolution.

3. Remedies. The Trustee may, if an Event of Default is not remedied, take such steps and institute such proceedings as it deems appropriate to collect all sums owing and to protect the rights of bondowners. If an Event of Default exists there is no right to accelerate payment of all or any of the interest on or principal of the Bonds not then due and payable. The owners of the Bonds shall be deemed to irrevocably appoint the Trustee as the lawful trustee of the bondowners. The owners of at least 66% in principal amount of the outstanding Bonds may, in certain circumstances, direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any power conferred upon the Trustee.

No bondowner may institute any proceeding for the enforcement of the Bond Resolution unless an Event of Default is continuing and the owners of not less than 66% in principal amount of the outstanding Bonds have given the District and the Trustee written notice to institute such proceeding and the Trustee has refused or neglected to comply within a reasonable time.

**Supplemental Resolutions**

1. Supplemental Resolutions Without Consent of Bondowners. The Board may adopt a supplemental resolution authorizing the issuance of Additional Bonds or a resolution amending or supplementing the Bond Resolution (a) to add to the covenants and agreements of the District in the Bond Resolution other covenants and agreements that will not adversely affect the interest of the bondowners in any material way, (b) to cure any ambiguities or correct any defective provisions in the Bond Resolution or any supplemental resolution which shall not adversely affect the bondowners' interest in any material way, or (c) to add conditions for the issuance of Additional Bonds after the Term of the Bonneville Agreements.

2. Supplemental Resolutions With Consent of Bondowners. With the consent of the owners of not less than 50% in principal amount of the outstanding Bonds, the District may adopt a resolution amending or supplementing the Bond Resolution; provided, that, without the specific consent of the owner of each Bond that would be affected, no such supplemental resolution shall: (a) change the fixed maturity date for the payment of the principal of any Bond or the date for the payment of interest or the terms of the redemption thereof, or reduce the principal amount of any Bond or the rate of interest thereon or the redemption price (or the redemption premium) payable upon the redemption or prepayment thereof; (b) reduce the percentage of Bonds the owners of which are required to consent to any Supplemental Resolution; (c) give to any Bond any preference over any other Bond; or (d) create any pledge of the Cowlitz Falls Revenues superior or equal to the pledge of and lien and charge for the payment of the Bonds.

**Consent of Bonneville**

During the term of the Bonneville Agreements, any decision required to be made by the District under the Bond Resolution shall require the concurrence of Bonneville.

**APPENDIX C**

**PROPOSED FORM OF LEGAL OPINION**

Public Utility District No. 1 of Lewis County
Chehalis, Washington

Citigroup Global Markets Inc.
Seattle, Washington

Seattle-Northwest Securities Corporation
Seattle, Washington

Bonneville Power Administration
Portland, Oregon

Re: Public Utility District No. 1 of Lewis County, Washington, Cowlitz Falls Project Revenue Refunding Bonds, Series 2003

Ladies and Gentlemen:

We have acted as bond counsel to Public Utility District No. 1 of Lewis County, Washington (the "District") and examined a certified transcript of all of the proceedings taken in the matter of the issuance by the District of its Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 in the aggregate principal amount of $146,210,000 (the "2003 Bonds"), issued to provide funds to refund the outstanding Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991 (the "1991 Bonds") and Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 1993 (the "1993 Bonds") and to pay the cost of issuance of the 2003 Bonds. The 2003 Bonds will be issued pursuant to Resolution No. 2245 approved June 19, 2003 (the "Bond Resolution").

The 2003 Bonds are subject to prior redemption as set forth in the Bond Resolution.

As to questions of fact material to our opinion, we have relied upon the certified proceedings and other certifications of public officials furnished to us without undertaking to verify the same by independent investigation.

From such examination it is our opinion, as of this date and under existing law, that:

1. The District has the right and power under the laws of the State of Washington to adopt the Bond Resolution, and the Bond Resolution has been duly and lawfully adopted by the District, is in full force and effect, is valid and binding upon the District and is enforceable in accordance with its terms.

2. The Bond Resolution creates valid pledges of (i) Cowlitz Falls Revenues, which include all income, revenue and payments derived by the District in connection with the Cowlitz Falls Project, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Project and certain other money, including payments received or receivable pursuant to the Power Purchase Contract, exclusive of any payments received under the Payment Agreement, certain insurance proceeds, and income pledged to the defeasance of specific revenue bonds, and (ii) money and assets, if any, credited to the Cowlitz Falls Project Revenue Fund, the Bond Fund, or any junior lien fund except proceeds from junior lien obligations, exclusive of money to be rebated to the federal government. Such pledges constitute a lien and charge equal in rank to the lien on such proceeds, revenues, money and securities required to pay and secure obligations issued on a parity with the 2003 Bonds and are superior to all other charges of any kind or nature.

3. The District is duly authorized and entitled to issue the 2003 Bonds, and the 2003 Bonds have been duly and validly authorized and issued by the District in accordance with the laws of the State of Washington. The 2003 Bonds constitute valid and binding obligations of the District as provided in the Bond Resolution, are enforceable in accordance with their terms and the terms of the Bond Resolution and are entitled to the benefits of the Bond Resolution. The 2003 Bonds are not general obligations of the District and are payable solely from the sources specified in the Bond Resolution. Neither the State of Washington nor any political subdivision thereof, other than the District, is obligated to pay the principal of, premium, if any, or interest on the 2003 Bonds.

4. Interest on the 2003 Bonds is excluded from gross income for purposes of federal income taxation pursuant to Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). The 2003 Bonds are not private activity bonds. Interest on the 2003 Bonds is not an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals or corporations, but is taken into account in the computation of adjusted current earnings for purposes of the corporate alternative minimum tax under Section 55 of the Code. The opinions stated in this paragraph are subject to the condition that the District comply with all requirements of the Code that must be satisfied subsequent to the issuance of the 2003 Bonds in order that interest thereon be, or continue to be, excluded from gross income for federal income tax purposes. The District has covenanted to comply with all such requirements. Failure to comply with certain of such requirements may cause interest on the 2003 Bonds to be included in gross income for federal income tax purposes retroactive to the date of issuance of the 2003 Bonds.

Except as stated herein, we express no opinion regarding any federal, state or local tax consequences arising with respect to ownership of the 2003 Bonds.

The opinions contained in paragraphs 1, 2 and 3 above are qualified to the extent that the enforcement of the rights and remedies of such owners of the 2003 Bonds may be limited by laws relating to bankruptcy, reorganization, insolvency, moratorium or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and the exercise of judicial discretion.

Very truly yours,

PRESTON GATES & ELLIS LLP

By
Nancy M. Neraas

## APPENDIX D

## BOOK-ENTRY SYSTEM

*The following information has been provided by The Depository Trust Company, New York, New York ("DTC"). The District makes no representation regarding the accuracy or completeness thereof. Each actual purchaser of a 2003 Bond (a "Beneficial Owner") should therefore confirm the following with DTC or the Participants (as hereinafter defined).*

DTC will act as securities depository for the 2003 Bonds. The 2003 Bonds will be issued as fully-registered bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered bond certificate will be issued for each maturity of the 2003 Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC, the world's largest depository, 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 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 85 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, Government Securities Clearing Corporation, MBS Clearing Corporation, and Emerging Markets Clearing Corporation, (NSCC, GSCC, MBSCC, and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange, Inc., 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, and trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the 2003 Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the 2003 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2003 Bond ("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 Owners entered into the transaction. Transfers of ownership interests in the 2003 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 2003 Bonds, except in the event that use of the book-entry system for the 2003 Bonds is discontinued.

To facilitate subsequent transfers, all 2003 Bonds deposited by 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 2003 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 2003 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2003 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.

When notices are given, they shall be sent by the Bond Registrar to DTC only. 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.

Redemption notices shall be sent to DTC. If less than all of the 2003 Bonds within a series are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2003 Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the District 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 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the 2003 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 District or the Bond Registrar, 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 (nor its nominee), the Bond Registrar, or the District, 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 any other nominee as may be requested by an authorized representative of DTC) is the responsibility of the District or the Bond Registrar, 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 securities depository with respect to the 2003 Bonds at any time by giving reasonable notice to the District and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, 2003 Bond certificates are required to be printed and delivered.

The District may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, 2003 Bond certificates will be printed and delivered.

**With respect to 2003 Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, the District and the Bond Registrar shall have no responsibility or obligation to any Participant or to any person on behalf of whom a Participant holds an interest in the 2003 Bonds with respect to (i) the accuracy of the records of DTC, Cede & Co. or any Participant with respect to any ownership interest in the 2003 Bonds; (ii) the delivery to any Participant or any other person, other than a bond owner as shown on the Bond Register, of any notice with respect to the 2003 Bonds, including any notice of redemption; (iii) the payment to any Participant or any other person, other than a bond owner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the 2003 Bonds; (iv) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the 2003 Bonds; (v) any consent given or action taken by DTC as registered owner; or (vi) any other matter. The District and the Bond Registrar may treat and consider Cede & Co., in whose name each 2003 Bond is registered on the Bond Register, as the holder and absolute owner of such 2003 Bond for the purpose of payment of principal and interest with respect to such 2003 Bond, for the purpose of giving notices of redemption and other matters with respect to such 2003 Bond, for the purpose of registering transfers with respect to such 2003 Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the Participant acquires an interest in the 2003 Bonds.**

## APPENDIX E

## SUMMARY OF THE
## POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT

A summary of certain provisions of the Power Purchase Contract between the District and Bonneville (each a "Party" and together the "Parties") relating to the Cowlitz Falls Project is set forth below. The summary is not to be considered a full statement of the Power Purchase Contract or the Payment Agreement and is qualified by reference to the complete text of the Power Purchase Contract and the Payment Agreement.

## POWER PURCHASE CONTRACT

### Term

The Contract is effective from the date of its execution and delivery to the District (May 23, 1991) through June 30, 2032, unless earlier terminated (the "Term").

### Certain Definitions Used in the Power Purchase Contract

"Financing Costs" means the costs associated with the authorization, issuance and sale of Cowlitz Falls Bonds, including but not limited to reserve and contingency funds, working capital, capitalized interest, debt service reserve, bond discount and finance expenses, letter of credit fees, bond insurance, and fees for bond counsel, bond printing, financial advisor, bond registrar/paying agent and Trustee, less any net receipts related to financing.

"Operating Year" has the same meaning as in the Bond Resolution. See Appendix B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution."

"Operation and Maintenance Costs" has the same meaning as in the Bond Resolution. See Appendix B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution."

"Other Renewal and Replacement Costs" has the same meaning as in the Bond Resolution. See Appendix B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution."

"Project Output" means the entire amount of capacity and energy including test energy, less station service, generated and available at the Project during the Term.

"Project Power Costs" has the same meaning as "Cowlitz Falls Project Power Costs" in the Bond Resolution. See Appendix B — "SUMMARY OF THE BOND RESOLUTION — Certain Definitions Used in the Bond Resolution."

"Special Operation and Maintenance Costs" includes costs of renewals and replacements that are not "Other Renewals and Replacements," spare parts not capitalized, labor costs (including benefits but excluding taxes), consumables, transportation expenses, and administrative and general expenses incurred to maintain and operate the Project.

"Uncontrollable Force" means an act or event beyond the reasonable control of a Party, and which by exercise of due diligence and foresight such Party could not reasonably have been expected to avoid or remove, which impairs the ability of the Party to perform, and includes, but is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, accident, fire, lightning and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities against any action taken or not taken by a Party, after a good faith effort by the appropriate Party to obtain: (i) relief from such order; or (ii) any necessary authorizations or approvals from any governmental agency or regulatory authority.

**Purchase and Sale of Project Output**

The District agrees to sell and deliver, and Bonneville agrees to purchase and accept delivery of, the entire Project Output during the Term, subject to the terms of the Power Purchase Contract. Bonneville agrees to pay to the District during each Operating Year (or portions thereof) of the Term an amount equal to Project Power Costs, whether or not the Project or any part thereof has been completed, terminated, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance of any Party to any agreement for any cause whatever.

**Annual Operating Budget**

Commencing no later than 120 days prior to the start of each Operating Year during the Term, the Parties shall commence development of a mutually agreeable annual operating budget covering a prospective seven Operating Year period for specified Project Power Costs. Each annual operating budget shall specify the amounts and due dates for all payments from Bonneville to the District for Project Power Costs during the next two Operating Years.

Bonneville shall pay to the Trustee the portion of Project Power Costs consisting of Annual Debt Service on or before the date such amounts are due under the Bond Resolution.

As part of the annual operating budget process the Parties shall consult and mutually agree upon the need for, timing of and means of funding any Other Renewal and Replacement Costs. Prior to the start of each annual operating budget process a relative efficiency test must be performed on the Project. After consultation with the District, Bonneville shall determine what corrective measures are needed to remedy the loss of efficiency, and shall include funding for such corrective measures in the annual operating budget. The District shall promptly implement such corrective measures.

**Limitations on Certain Payments**

The District's obligation to reimburse Bonneville for certain Special Operation and Maintenance Costs, and Bonneville's obligation to make incentive payments for Special Operation and Maintenance Costs, shall be limited during any Operating Year to an amount calculated by multiplying 3.6 mills per kilowatt-hour (9.5% of the District's 1988 retail rates) by the District's total retail sales (in kilowatt-hours) during the Operating Year in which the payment obligation was incurred. The cumulative limit of the District's obligation is the amount remaining in the Lewis Investment Account in the Construction Fund at the time of fund disbursements inflated by the Gross National Product Implicit Price Deflator as published by the U.S. Department of Commerce.

**Point of Delivery**

The District will deliver and Bonneville will receive Project Output at a point that is approximately six miles west of Tacoma City Light's Mossyrock Dam and that is in the vicinity of the Silver Creek-Cinebar County Road where the 230 kV facilities of Tacoma and Bonneville are connected with an interconnection voltage of 230 kV.

**Additional Bonds**

When requested by Bonneville, the District shall use its best efforts to arrange for the refinancing or refunding of Cowlitz Falls Bonds, the financing of Delay Costs, the financing of Termination Costs for site restoration, and the financing of all or any portion of any Other Renewal and Replacement Costs for the Project. Such requests by Bonneville shall not require the District to issue and sell Cowlitz Falls Bonds with maturities which are subsequent to the Term of the Contract, unless otherwise agreed to by the Parties. Bonneville shall compensate the District for all costs incurred by the District in undertaking any financing, refinancing or refunding effort. Bonneville shall withdraw any request for financing, refinancing or refunding when the District demonstrates that complying with such request will detrimentally affect its costs, or materially impair its ability, to finance facilities necessary to provide reliable service to the District's retail customers.

**Consent of Bonneville**

The District may not adopt any resolution, or indenture, or incur any indebtedness which constitutes a charge on the Project through which the District will acquire funds during the Term of the Power Purchase Contract to pay costs of the Project without first obtaining Bonneville's written consent.

**Right of First Refusal**

For the period from the expiration of the Power Purchase Contract (June 30, 2032) until the end of the Project's second FERC License, if any, or until July 1, 2066, whichever is later, Bonneville shall have the right of first refusal to purchase firm Project capability on the same terms under which the District has entered into a memorandum of sale evidencing an intention to sell firm Project capability.

**Arbitration**

The Parties agree to submit to binding arbitration most issues, disputes and controversies arising out of the Power Purchase Contract that the Parties have the legal authority to arbitrate and that cannot be otherwise resolved by discussions between the Parties.

**Contractor Performance**

All contracts between the District and Project contractors and subcontractors must require such contractors and subcontractors to perform in accordance with contract specifications. Such contracts must grant Bonneville certain audit rights and must assign to Bonneville or the Project, as appropriate, any financial penalties or payments imposed in such contracts. The Parties will make a good faith effort to provide incentives in such contracts for constructing the Project on schedule and under budget.

**Uncontrollable Force**

Any obligation of a Party to perform under the Power Purchase Contract shall be excused when failure to perform such obligation is due to an Uncontrollable Force; provided that a Party's obligation to pay or reimburse the other for Project Output, Project Holding Costs, and certain other payments shall not be excused. A Party must exercise due diligence to remove its inability to perform with reasonable dispatch. However, neither Party shall be required under the Power Purchase Contract to settle any strike or labor dispute in which it may be involved.

**Use of Project Output**

From the expiration date of the Power Purchase Contract until the later of the end of the second FERC License issued to the District to operate the Project or July 1, 2066, if and to the extent that the District is licensed to operate the Project, the District agrees to dedicate the Project's firm capability to serve the District's loads under its power sales contract in effect during such period with Bonneville or its successor.

Subject to Bonneville's election, the District is relieved of this obligation to dedicate firm capability during any Operating Year when the cost of the firm capability of the Project, calculated as set forth in the Contract, exceeds the District's cost of wholesale power purchased from Bonneville.

**Assignment**

Each of the Parties agrees that it will not sell, assign or transfer its interests, rights or obligations under the Power Purchase Contract except to any corporation or entity required or permitted under the Bond Resolution or so long as the 2003 Bonds are outstanding, to any corporation or other entity approved by the other Party. In addition, Bonneville may sell, assign, transfer or otherwise dispose of Project Output in any manner in its sole discretion. Notice of any such assignment or transfer by a Party must be given to the other Party as provided in the Power Purchase Contract. The Power Purchase Contract inures to the benefit of and will be binding on the successors and assigns of the Parties.

## PAYMENT AGREEMENT

A summary of certain provisions of the Payment Agreement between Bonneville and the Trustee relating to the Cowlitz Falls Project (the "Payment Agreement") is set forth below. Reference is made to the complete text of the Payment Agreement for all of the provisions thereof.

**Payment Obligation**

The Payment Agreement provides that if and to the extent that Bonneville does not make payments of debt service on the Cowlitz Falls Bonds at the time and in the manner described by the Power Purchase Contract, Bonneville will make such payments not later than the dates on which such payments are described by the provisions of the Power Purchase Contract. To the extent the amounts required to be paid under the Bond Resolution as principal and interest due and payable on the Cowlitz Falls Bonds will not be available in the Bond Fund to be paid when due, Bonneville will make such payments to the Trustee for the benefit of the bondholders. Such payments shall be made at the time and place and in such manner as to enable the payments to Bondholders to be made on the dates required by the Bond Resolution. All payments required to be made by Bonneville under the Payment Agreement will be made solely from the Bonneville Fund or from such other funds as shall now or hereafter become legally available for such purposes.

The Payment Agreement does not affect the rights of the District, the Trustee or the bondowners under the Bond Resolution. The Payment Agreement serves as further security for the Cowlitz Falls Bonds (in addition to the security provided for by the Bond Resolution and the Power Purchase Contract) and will remain in full force and effect without impairment of any of its obligations until the earlier of termination of the Power Purchase Contract according to its terms or the date on which no Cowlitz Falls Bonds remain outstanding.

**Default and Remedies**

The Trustee has the right to enforce the Payment Agreement and to protect the interest of the bondowners in the manner provided by law. In the event of a default under the Payment Agreement, the Trustee may proceed first and directly against the United States without proceeding against any other person, without exhausting any other remedies that it may have and without resorting to any other security held by the District or the Trustee. There is no right to acceleration of any payment obligation due under the Payment Agreement.

The Payment Agreement is not a guaranty, and Bonneville waives any defense of presentment, demand for payment, protest, division, discussion or notice of nonpayment or dishonor and all other defenses whatsoever based upon notices or demands relating to the Cowlitz Falls Bonds. In addition, no set-off, counterclaim, reduction or diminution of any obligation or any defense of any kind or nature (other than performance by Bonneville of its obligations under the Payment Agreement) that Bonneville may have or assert against the District, the Trustee or any bondowner is available under the Payment Agreement.

Bonneville will pay all costs, expenses and fees, including all reasonable attorneys' fees, that the Trustee may incur in enforcing or attempting to enforce the Payment Agreement.

Bonneville has no recourse against the District under the Payment Agreement for any payment, or the performance of any other obligation, made by Bonneville pursuant to the Payment Agreement. This provision does not affect the rights of Bonneville or the District under the Power Purchase Contract.

In the event that a decision is entered by any court of competent jurisdiction rendering the Power Purchase Contract unenforceable in any respect deemed material by Bonneville, Bonneville has the option to direct the termination of the Project and/or the redemption of part or all of the Cowlitz Falls Bonds outstanding, all according to the procedures prescribed by the Power Purchase Contract and Bond Resolution. Such termination will be effected as if initiated by Bonneville pursuant to the Power Purchase Contract. All funds held by the Trustee or the District that are proceeds of the Cowlitz Falls Bonds not otherwise committed (and that are legally available for such purposes) may, at Bonneville's option, be applied to the costs of such redemption with the exception of moneys received by the District pursuant to the Power Purchase Contract as reimbursement for Lewis' Investment (as defined in the

Power Purchase Contract) in the Project. To the extent that such funds are not sufficient to cover the costs of any such redemption of the Cowlitz Falls Bonds, Bonneville will pay the balance of such costs.

If the Project is so terminated, all costs of such termination, including, but not limited to, compensation or damages payable to all contractors and the costs of site restoration and environmental mitigation, as required by law or regulatory order, shall be paid by Bonneville.

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APPENDIX F

Lewis County PUD PUBLIC UTILITY DISTRICT

# INDEPENDENT AUDITOR'S REPORT AND FINANCIAL STATEMENTS

## DECEMBER 31, 2002 AND 2001

## CONTENTS

**INDEPENDENT AUDITOR'S REPORT**

Board of Commissioners
Public Utility District No. 1 of Lewis County
Chehalis, Washington

We have audited the accompanying balance sheets of Public Utility District No. 1 of Lewis County as of December 31, 2002 and 2001 and the related statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the District's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Public Utility District No. 1 of Lewis County as of December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Moss Adams LLP

Vancouver, Washington
February 7, 2003

## PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY
## BALANCE SHEET

# ASSETS

| | | | DECEMBER 31, | |
|---|---|---|---|---|
| | Electric System | Cowlitz Falls System | 2002 Combined | 2001 Combined |
| UTILITY PLANT | | | | |
| Utility plant in service | $ 104,625,652 | $ 152,771,333 | $ 257,396,985 | $ 253,546,997 |
| Construction in progress | 4,499,911 | - | 4,499,911 | 4,557,114 |
| | 109,125,563 | 152,771,333 | 261,896,896 | 258,104,111 |
| Less accumulated depreciation | 25,967,785 | 23,331,961 | 49,299,746 | 44,664,120 |
| Net utility plant | 83,157,778 | 129,439,372 | 212,597,150 | 213,439,991 |
| OTHER PROPERTY AND INVESTMENTS | | | | |
| Special funds | - | 13,466,550 | 13,466,550 | 13,466,550 |
| Restricted investments | 11,000,000 | - | 11,000,000 | 11,000,000 |
| Total other property and investments | 11,000,000 | 13,466,550 | 24,466,550 | 24,466,550 |
| CURRENT ASSETS | | | | |
| Cash | 3,400,319 | 851,916 | 4,252,235 | 2,058,731 |
| Temporary investments | 6,300,000 | 1,000,000 | 7,300,000 | 9,200,000 |
| Accounts and other receivables, net | 4,664,093 | 3,263,526 | 7,927,619 | 7,799,549 |
| Inventories | 2,382,260 | - | 2,382,260 | 2,695,204 |
| Other | 116,419 | 220,267 | 336,686 | 263,925 |
| Total current assets | 16,863,091 | 5,335,709 | 22,198,800 | 22,017,409 |
| DEFERRED CHARGES AND OTHER ASSETS | | | | |
| Deferred cost recovery | - | 5,025,055 | 5,025,055 | 5,025,055 |
| Unamortized bond issuance costs | - | 989,295 | 989,295 | 1,063,719 |
| Conservation loans | 850,841 | - | 850,841 | 1,019,995 |
| Total deferred charges and other assets | 850,841 | 6,014,350 | 6,865,191 | 7,108,769 |
| | $ 111,871,710 | $ 154,255,981 | $ 266,127,691 | $ 267,032,719 |

## EQUITY AND LIABILITIES

| | Electric System | Cowlitz Falls System | DECEMBER 31, 2002 Combined | 2001 Combined |
|---|---|---|---|---|
| EQUITY | | | | |
| Retained earnings | $ 102,082,771 | $ - | $ 102,082,771 | $ 100,481,224 |
| Contributions in aid of construction | 1,309,971 | - | 1,309,971 | 1,309,971 |
| Total equity | 103,392,742 | - | 103,392,742 | 101,791,195 |
| LONG-TERM DEBT | | | | |
| Revenue bonds, net of current maturities | - | 147,969,887 | 147,969,887 | 151,065,828 |
| Unamortized discount | - | (2,071,998) | (2,071,998) | (2,196,162) |
| Total long-term debt | - | 145,897,889 | 145,897,889 | 148,869,666 |
| CURRENT LIABILITIES | | | | |
| Warrants outstanding | 2,565,217 | 27,057 | 2,592,274 | 3,217,713 |
| Accounts payable | 485,766 | 35,671 | 521,437 | 161,989 |
| Accrued liabilities | 4,702,591 | 2,393,448 | 7,096,039 | 7,189,100 |
| Operations and maintenance advance | - | 1,851,916 | 1,851,916 | 1,389,748 |
| Customer deposits | 725,394 | - | 725,394 | 523,467 |
| Current maturities of long-term debt | - | 4,050,000 | 4,050,000 | 3,865,000 |
| Total current liabilities | 8,478,968 | 8,358,092 | 16,837,060 | 16,347,017 |
| DEFERRED CREDITS | - | - | - | 24,841 |
| | $ 111,871,710 | $ 154,255,981 | $ 266,127,691 | $ 267,032,719 |

*See accompanying notes.*

## PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY
## STATEMENT OF INCOME AND RETAINED EARNINGS

| | Electric System | Cowlitz Falls System | YEAR ENDED DECEMBER 31, 2002 Combined | 2001 Combined |
|---|---|---|---|---|
| REVENUE | $ 38,277,686 | $ 13,603,767 | $ 51,881,453 | $ 49,217,694 |
| OPERATING EXPENSES | | | | |
| Power supply | 25,971,627 | - | 25,971,627 | 20,244,164 |
| Other operating | 3,856,554 | 982,799 | 4,839,353 | 4,454,261 |
| Maintenance | 2,083,842 | 391,700 | 2,475,542 | 2,532,951 |
| Depreciation | 2,528,419 | 2,733,559 | 5,261,978 | 8,239,849 |
| Taxes | 2,552,246 | 101,983 | 2,654,229 | 2,331,240 |
| Total operating expenses | 36,992,688 | 4,210,041 | 41,202,729 | 37,802,465 |
| OPERATING INCOME | 1,284,998 | 9,393,726 | 10,678,724 | 11,415,229 |
| OTHER INCOME (EXPENSE) | | | | |
| Interest income | 361,647 | 895,099 | 1,256,746 | 1,698,479 |
| Interest expense | - | (9,141,795) | (9,141,795) | (9,350,695) |
| Amortization of debt expense | - | (1,152,647) | (1,152,647) | (1,165,093) |
| Revenue from merchandising | 98,407 | - | 98,407 | 101,363 |
| Expense of contract work | (101,352) | - | (101,352) | (100,481) |
| Other income (expense) | (42,153) | 5,617 | (36,536) | 6,031 |
| Total other income (expense) | 316,549 | (9,393,726) | (9,077,177) | (8,810,396) |
| NET INCOME | 1,601,547 | - | 1,601,547 | 2,604,833 |
| RETAINED EARNINGS, beginning of year | 100,481,224 | - | 100,481,224 | 97,876,391 |
| RETAINED EARNINGS, end of year | $ 102,082,771 | $ - | $ 102,082,771 | $ 100,481,224 |



*See accompanying notes.*

| | Electric System | Cowlitz Falls System | YEAR ENDED DECEMBER 31, 2002 Combined | 2001 Combined |
|---|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | | |
| Net income | $ 1,601,547 | $ - | $ 1,601,547 | $ 2,604,833 |
| Adjustments to reconcile net income to net cash from operating activities | | | | |
| Depreciation | 2,528,419 | 2,733,559 | 5,261,978 | 8,239,849 |
| Amortization | - | 1,152,647 | 1,152,647 | 1,165,093 |
| Change in assets and liabilities | | | | |
| Receivables | (127,717) | (353) | (128,070) | (3,309,883) |
| Inventories | 312,944 | - | 312,944 | (507,340) |
| Other current assets | (71,933) | (828) | (72,761) | 268,165 |
| Warrants outstanding | (638,233) | 12,794 | (625,439) | 977,489 |
| Accounts payable | 353,892 | 5,556 | 359,448 | (122,906) |
| Accrued liabilities | (76,094) | (16,967) | (93,061) | 1,119,263 |
| Operations and maintenance advance | - | 462,168 | 462,168 | 341,650 |
| Customer deposits | 201,927 | - | 201,927 | 50,274 |
| Deferred credits | (24,841) | - | (24,841) | (121,527) |
| Net cash from operating activities | 4,059,911 | 4,348,576 | 8,408,487 | 10,704,960 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | | |
| Conservation loans | 169,154 | - | 169,154 | (2,379) |
| CASH FLOWS FROM CAPITAL FINANCING ACTIVITIES | | | | |
| Utility plant additions, net of cost of removal and salvage proceeds | (4,397,729) | (21,408) | (4,419,137) | (5,465,469) |
| Principal payment on revenue bonds | - | (3,865,000) | (3,865,000) | (3,650,000) |
| Net cash from capital financing activities | (4,397,729) | (3,886,408) | (8,284,137) | (9,115,469) |
| CHANGE IN CASH AND CASH EQUIVALENTS | (168,664) | 462,168 | 293,504 | 1,587,112 |
| CASH AND CASH EQUIVALENTS, beginning of year | | | | |
| Cash | 1,468,983 | 589,748 | 2,058,731 | 1,771,619 |
| Temporary investments | 8,400,000 | 800,000 | 9,200,000 | 7,900,000 |
| | 9,868,983 | 1,389,748 | 11,258,731 | 9,671,619 |
| CASH AND CASH EQUIVALENTS, end of year | | | | |
| Cash | 3,400,319 | 851,916 | 4,252,235 | 2,058,731 |
| Temporary investments | 6,300,000 | 1,000,000 | 7,300,000 | 9,200,000 |
| | $ 9,700,319 | $ 1,851,916 | $ 11,552,235 | $ 11,258,731 |
| SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION | | | | |
| Cash paid for interest | $ - | $ 9,187,693 | $ 9,187,693 | $ 9,405,030 |

## Note 1 - Nature Of Organization And Operations

Public Utility District No. 1 of Lewis County (the District) is a municipal corporation of the State of Washington and is governed by an elected three member board. The District was organized in 1936, pursuant to a general election in accordance with the Enabling Act, and commenced its operations in 1939. The District has its administrative offices in Chehalis, Washington, which is located in southwestern Washington. The District provides electric service to substantially all of Lewis County, except for the City of Centralia.

The District constructed and, beginning in June 1994, operates the Cowlitz Falls Hydroelectric Dam on the upper Cowlitz River in eastern Lewis County, Washington (See Note 9). The Electric System and Cowlitz Falls System are separate operating systems.

## Note 2 - Summary Of Significant Accounting Policies

**Basis of accounting and presentation** - The financial statements of the District have been prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America (GAAP) as applied to governmental units. The District applies certain Governmental Accounting Standards Board (GASB) statements and has elected to apply Financial Accounting Standards Board (FASB) statements issued after November 30, 1989. The Uniform System of Accounts, as proscribed by the Federal Energy Regulatory Commission (FERC), is the basis for the District's accounting policies.

The accounting records of the District are maintained in accordance with methods proscribed by the State Auditor under authority of Chapter 43.09 RCW.

The accompanying financial statements include the individual and combined statements of financial position of the Electric System and Cowlitz Falls System (generation system) and the results of operations and cash flows for each system.

**Concentration of credit risk** - The District's financial instruments that are exposed to concentrations of credit risk consist primarily of cash and receivables.

The District maintains its cash in bank deposit accounts which, at times, exceed federally insured limits. However, all deposits made with state-approved depositories are protected under the State's Public Deposit Protection Commission (PDPC). Except for special fund investments, all of the District's deposits are with PDPC approved commercial banks. The District has not experienced any losses in such accounts and believes its cash and cash equivalents are not exposed to any significant credit risk.

Credit is extended to customers generally without collateral requirements, however, deposits are obtained from certain customers and formal shut-off procedures are in place.

**Note 2 - Summary Of Significant Accounting Policies (Continued)**

**Utility plant and depreciation** - Utility plant assets are stated at cost. Cost includes contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and other similar overhead items. For the Electric System, the provision for depreciation is determined by the straight-line method over the estimated useful lives of the assets. The cost of maintenance and repairs is expensed as incurred; renewals, replacements and betterments are capitalized. For the Cowlitz Falls System, depreciation, renewals and replacements are recognized on the basis of the Amendatory Power Purchase Contract between the District and BPA (See Note 9).

Cost of assets retired are removed from the asset accounts and charged to the accumulated depreciation accounts, together with removal costs less any proceeds from sales.

**Investments** - All investments of the District are obligations of the U.S. Government or deposits with Washington State banks and are carried at fair value.

**Cash and cash equivalents** - The District considers all highly liquid investments, including restricted cash, with a maturity of three months or less when purchased to be cash equivalents.

**Accounts receivable -** Management periodically assesses the collectability of accounts receivable. This assessment provides the basis for the allowance for doubtful accounts and the related bad debt expense. The allowance for doubtful accounts was $120,547 and $133,610 at December 31, 2002 and 2001, respectively.

**Inventories -** Material and supply inventories are stated at average cost.

**Unamortized bond discounts and issuance costs -** Bond discounts and issuance costs relating to revenue bonds are amortized by the effective interest method over the life of bond issues using a weighted average of the face amount of bonds outstanding.

**Deferred cost recovery** - Deferred cost recovery consists of amounts to be recovered over the term of the Amendatory Power Purchase Contract with BPA (See Note 9).

**Compensated absences -** The District accrues accumulated unpaid vacation benefits as the obligation is incurred. The accrued liability for unpaid vacation leave at December 31, 2002 and 2001 was $475,035 and $466,108, respectively. Employees covered by PERS I (See Note 5), are entitled to, upon retirement, the use of up to 60 days of unused vacation for calculation of retirement benefits. PERS actuarially determines the cost for these additional benefits and bills the District for a portion of them on a one-time basis. These additional costs do not materially effect the District's financial statements.

**Operations and maintenance advance** - Operations and maintenance advance represents unspent BPA operation and maintenance advances recognized in accordance with the Amendatory Power Purchase Contract with BPA (See Note 9).

## Note 2 - Summary Of Significant Accounting Policies (Continued)

**Customer deposits -** The District requires deposits from certain customers upon request for service. The customer deposits are held to defray potential uncollected accounts and other contingencies. The deposits are refundable under certain circumstances.

**Revenue recognition -** The District recognizes Electric System revenue as earned. Substantially all residential and small commercial customers are billed bimonthly while large commercial and industrial customers are billed monthly. The District utilizes cycle billing and records revenue billed to its customers when the meters are read. At year-end, revenues from electric power delivered but not yet billed are accrued. At December 31, 2002 and 2001 unbilled revenue was approximately $2,100,000 and $1,900,000, respectively. Revenues for the Cowlitz Falls System are recognized on the basis of the Amendatory Power Purchase Contract between the District and BPA (See Note 9).

**Use of estimates** - The preparation of the 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 amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

## Note 3 - Investments

Investments consist of the following:

| | DECEMBER 31, 2002 | | DECEMBER 31, 2001 | |
|---|---|---|---|---|
| | Electric System | Cowlitz Falls System | Electric System | Cowlitz Falls System |
| | Fair Value | Fair Value | Fair Value | Fair Value |
| OTHER PROPERTY AND INVESTMENTS | | | | |
| Special funds | | | | |
| Repurchase agreement | $ - | $ 13,466,550 | $ - | $ 13,466,550 |
| Restricted investments | | | | |
| Certificates of deposit | 11,000,000 | - | 11,000,000 | - |
| | 11,000,000 | 13,466,550 | 11,000,000 | 13,466,550 |
| CURRENT ASSETS | | | | |
| Temporary investments | | | | |
| Certificates of deposit | 6,300,000 | 1,000,000 | 8,400,000 | 800,000 |
| | $ 17,300,000 | $ 14,466,550 | $ 19,400,000 | $ 14,266,550 |

**Note 3 - Investments (Continued)**

Special Funds consist of the Cowlitz Falls System reserve sinking fund. The fund is invested under a Master Repurchase Agreement sponsored by the American International Group Matched Funding Corporation (AIGMFC), a Delaware corporation. The agreement contains various restrictions and requirements concerning withdrawal frequencies and investment options. The agreement requires AIGMFC to maintain collateral securities, of permitted Treasury and Federal agency obligations, equal to or exceeding the market value of repurchase agreement holdings. In addition, the agreement performance is guaranteed by American International Group, Inc., a Delaware corporation, in favor of the Bank Trustee.

Restricted investments consist of funds set aside and invested by the District in a major catastrophe fund. The balance provides the District with emergency funds should the District face a catastrophe, such as a major wind storm or other extraordinary event. As of December 31, 2002 and 2001, the District had invested these restricted funds in certificates of deposit at Washington State commercial banks as permitted by law.

Temporary investments consist of cash in excess of current working capital requirements that is invested in short-term certificates of deposit in order to obtain a higher rate of return. The certificates of deposit are with Washington State commercial banks as permitted by law.

## Note 4 - Utility Plant in Service

### Electric System

| | Balance December 31, 2001 | Additions | Retirements | Balance December 31, 2002 |
|---|---|---|---|---|
| Distribution system | $ 69,572,723 | $ 4,030,050 | $ 744,981 | $ 72,857,792 |
| Transmission system | 19,209,958 | 307,468 | - | 19,517,426 |
| Hydraulic system | 1,421,160 | - | - | 1,421,160 |
| General plant | 10,480,445 | 294,035 | 66,339 | 10,708,141 |
| Intangible plant | 121,133 | - | - | 121,133 |
| | $ 100,805,419 | $ 4,631,553 | $ 811,320 | $ 104,625,652 |

### Cowlitz Falls System - Generation

| | Balance December 31, 2001 | Additions | Retirements | Balance December 31, 2002 |
|---|---|---|---|---|
| Hydraulic system | $ 150,229,878 | $ 5,763 | $ - | $ 150,235,641 |
| Transmission system | 2,174,630 | - | - | 2,174,630 |
| General plant | 337,070 | 23,992 | - | 361,062 |
| | $ 152,741,578 | $ 29,755 | $ - | $ 152,771,333 |

## Note 5 - Pension, Deferred Compensation Plan and Post-Retirement Benefits

**Pension - Public Employees Retirement System (PERS) Plans 1, 2, and 3**
Substantially all the District's full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing multiple-employer public employee defined benefit and defined contribution retirement plans. The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to: Department of Retirement Systems, Communications Unit, P.O. Box 48380, Olympia, WA 98504-8380. The following disclosures are made pursuant to GASB Statement No. 27, *Accounting for Pensions by State and Local Government Employers*.

**Note 5 - Pension, Deferred Compensation Plan and Post-Retirement Benefits (Continued)**

**Plan description** - PERS is a cost-sharing multiple-employer retirement system comprised of three separate plans for membership purposes: Plans 1 and 2 are defined benefit plans and Plan 3 is a combination defined benefit/defined contribution plan. PERS participants who joined the system by September 30, 1977, are Plan 1 members. Those who joined on or after October 1, 1977 and by August 31, 2002 are Plan 2 members unless they exercise an option to transfer their membership to Plan 3. PERS participants joining the system after September 1, 2002 have the option of choosing membership in either PERS Plan 2 or PERS Plan 3. The option must be exercised within 90 days of employment. An employee is reported in Plan 2 until a choice is made. Employees who fail to choose within 90 days default to PERS Plan 3. PERS defined benefit retirement benefits are financed from a combination of investment earnings and employer and employee contributions. PERS retirement benefit provisions are established in state statute and may be amended only by the State Legislature.

Plan 1 retirement benefits are vested after an employee completes five years of eligible service. Plan 1 members are eligible for retirement at any age after 30 years of service, or at the age of 60 with five years of service, or at the age of 55 with 25 years of service. The annual pension is 2 percent of the average final compensation per year of service, capped at 60 percent. The average final compensation is based on the greatest compensation during any 24 eligible consecutive compensation months. If qualified, after reaching the age of 66 a cost-of-living allowance is granted based on years of service credit and is capped at 3 percent annually.

Plan 2 retirement benefits are vested after an employee completes five years of eligible service. Plan 2 members may retire at the age of 65 with five years of service, or at the age of 55 with 20 years of service, with an allowance of 2 percent of the average final compensation per year of service. The average final compensation is based on the greatest compensation during any eligible consecutive 60-month period. Plan 2 retirements prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a 3 percent per year reduction applies; otherwise an actuarial reduction will apply. There is no cap on years of service credit; and a cost-of-living allowance is granted (indexed to the Seattle Consumer Price Index), capped at 3 percent annually.

Plan 3 has a dual benefit structure. Employer contributions finance a defined benefit component, and member contributions finance a defined contribution component. The defined benefit portion provides a benefit calculated at 1 percent of the average final compensation per year of service. The average final compensation is based on the greatest compensation during any eligible consecutive 60-month period. Plan 3 members become eligible for retirement if they have: at least ten years of service; or five years including twelve months that were earned after age 54; or five service credit years earned in PERS Plan 2 prior to June 1,2003. Plan 3 retirements prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a 3 percent per year reduction applies; otherwise an actuarial reduction will apply. There is no cap on years of service credit; and Plan 3 provides the same cost-of-living allowance as Plan 2. The defined contribution portion can be distributed in accordance with an option selected by the member, either as a lump sum or pursuant to other options authorized by the Employee Retirement Benefits Board.

**Note 5 - Pension, Deferred Compensation Plan and Post-Retirement Benefits (Continued)**

**Funding policy -** Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates, Plan 2 employer and employee contribution rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at 6 percent and do not vary from year to year. The employer and employee contribution rates for Plan 2 and the employer contribution rate for Plan 3 are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. All employers are required to contribute at the level established by the Legislature. PERS Plan 3 defined contribution is a non-contributing plan for employers. Employees who participate in the defined contribution portion of PERS Plan 3 do not contribute to the defined benefit portion of PERS Plan 3. The Employee Retirement Benefits Board sets Plan 3 employee contribution rates. Six rate options are available ranging from 5 to 15 percent; two of the options are graduated rates dependent on the employee's age. The methods used to determine the contribution requirements are established under state statute in accordance with chapters 41.40 and 41.45 RCW.

The required contribution rates expressed as a percentage of current-year covered payroll, as of December 31, 2002, were as follows:

| | PERS Plan 1 | PERS Plan 2 | PERS Plan 3 |
|---|---|---|---|
| Employer * | 1.32% | 1.32% | 1.32%** |
| Employee | 6.00% | 0.65% | *** |

* The employer rates include the employer administrative expense fee currently set at 0.22%.
** Plan 3 defined benefit portion only.
*** Variable from 5.0% minimum to 15.0% maximum based on rate selected by the PERS 3 member.

The District's required contributions for the years ended December 31, 2002 and 2001 were $58,037 and $150,160, respectively.

**Deferred compensation plan**
The District maintains a deferred compensation plan (Internal Revenue Code Section 457) for all eligible employees. The plan is entirely funded by voluntary employee contributions. The District has entered into a contractual relationship with the State of Washington Deferred Compensation Program placing all plan assets into trust for the exclusive benefit of participants and their beneficiaries.

**Post-retirement benefits**
The District provides post-retirement health care benefits for retired employees until age 65. These benefits, which are entirely District-paid and cover a limited population, are expensed as paid and amounted to $136,195 and $76,393 for the years ended December 31, 2002 and 2001, respectively.

**Note 6 - Energy Northwest Projects**

**Nuclear Projects 1, 2 and 3 -** Energy Northwest was formerly Washington Public Power Supply System (WPPSS). The District entered into "Net Billing Agreements" with Energy Northwest and the Bonneville Power Administration. Under terms of these agreements, the District purchased a maximum of 1.276 percent of the capacity of Energy Northwest Nuclear Projects (WNP) 1, 2.274 percent of WNP 2, and 1.103 percent of Energy Northwest's 70 percent ownership share of WNP 3. The District in turn sold this capability to BPA. Under the "Net Billing Agreements," BPA is unconditionally obligated to pay the District, and the District is unconditionally obligated to pay Energy Northwest the pro rata share of the total annual costs of each project, including debt service on revenue bonds issued to finance the projects, whether or not the projects are completed, operable or operating and notwithstanding the suspension, reduction or curtailment of the projects' outputs.

WNP 2 commenced commercial operation in December 1984. In May 1994 BPA and Energy Northwest terminated WNP 1 and WNP 3, subject to repayment of the debt service on the outstanding revenue bonds. As of November 19, 1984, the District was no longer a member of Energy Northwest.

**Note 7 - Remediation Sites And Litigation**

**Coal Creek** - The District owns Lots 6 and 9 of the Chehalis Land and Timber Company's Coal Creek Subdivision to the City of Chehalis. From the 1950's to 1983, the property was leased to various businesses conducting transformer manufacture, storage, rebuilding and scrapping.

The State of Washington Department of Ecology advised a former lessee and the District of the discovery, in samples taken from the property, of PCB (polychlorinated biphenyls) concentrations in excess of the permitted limit. Under a consent decree issued by the United States Environmental Agency (EPA) (Civil Action No. C91 5470B), the District and other potentially responsible parties completed, in 1994, remedial action at the site. The EPA, by letter of May 9, 1995, issued a Certificate of Completion as part of the consent decree. A five year monitoring period, administered by the District, that was to end in 1999 is ongoing pending final release from the EPA.

**Other sites -** The District is associated with another site involving remediation of environmental contaminates. Clean-up costs are being paid from the PURMS Self-Insurance Fund (See Note 11) and result in no significant financial impact to the District.

**Note 7 - Remediation Sites And Litigation (Continued)**

**John T. and Margaret L. Kaech v. Lewis County Public Utility District No. 1, Lewis County Superior Court, Case No. 97-2-00130-5 -** Suit has been filed in Lewis County Superior Court by Mr. and Mrs. Kaech against the District asserting unspecified damages as a result of the alleged presence of stray voltage on plaintiffs' dairy farm. The claim has been referred to the PURMS Self-Insurance Fund for defense (See Note 11). This matter was previously tried in U.S. District Court in Tacoma, Washington and in December 1996 resulted in a hung jury. The case was tried again in December 1997 and the jury awarded the plaintiffs $1,089,000. The case was appealed and the judge's grant of a new trial was appealed by the plaintiff. The appellant court remanded the case for a new trial with the scope limited to determination of damages. Prior to date of re-trial , PURMS and its excess carrier, AEGIS, arrived at a compromise settlement with Mr. Kaech in the amount of $500,000. The case was officially dismissed on November 1, 2002. The settlement was borne by PURMS and AEGIS and will not materially effect the financial position of the District.

**Note 8 - Purchased Power Contracts**

Bonneville Power Administration (BPA) - On September 25, 2000, the District entered into a new ten-year power supply contract with BPA. The contract obligates the BPA to serve the District's net power requirements through September 30, 2011. The contract specifies BPA rates are subject to periodic rate review and adjustment. BPA increased rates 46% on October 1, 2001, decreased rates 5% on April 1, 2002, and increased rates 4% on October 1, 2002.

**Packwood Project Purchase** - In accordance with agreements between Energy Northwest (formerly WPPSS), BPA and 12 participants, Energy Northwest constructed the Packwood Project near Packwood, Washington, which began commercial operation in June 1964. The Project has a nameplate rating of 27,500 kilowatts and produces average annual energy of approximately 92 million kilowatt hours. Pursuant to a Power Sales Contract entered into by the District with Energy Northwest, the District has purchased 14.25 percent of the output of the Packwood Project and is obligated to pay Energy Northwest the same percentage of the annual cost thereof. Between 1996 and 2002, BPA purchased project energy directly from Energy Northwest. In October 2002 Benton and Franklin PUDs began purchasing project energy from Energy Northwest. To the extent that payments to Energy Northwest by BPA and Benton and Franklin PUDs are less than or exceed Packwood costs, the deficits are billed to or surpluses paid to all 12 participants based on each participant's share. In 2001, the Project incurred a loss, however, this loss was not passed-through to the participants. In 2002, because project revenues exceeded expenses, the District received from Energy Northwest the amount of $64,227.

In addition, the District and Energy Northwest have entered into a power transmission service agreement. The agreement calls for the District to receive monthly payments adjusted annually and expires in February 2010 unless terminated or extended. Revenue amounted to $350,456 for each of the years ended December 31, 2002 and 2001.

**Note 8 - Purchased Power Contracts (Continued)**

**Nine Canyon Wind Project** - The District has signed a Power Purchase Agreement with Energy Northwest for 2% of the output of the Nine Canyon Wind Project. The District's 2% share represents approximately 1 MW of capacity and based upon a 30% plant factor, approximately 2.6 million KWH on energy production annually.

The Nine Canyon Wind Project is owned by Energy Northwest and is located near the city of Kennewick, Washington. The Nine Canyon Wind Project began commercial operation in September of 2002.

The District signed an Agreement with Grant County PUD No. 2 to provide scheduling and storage services for the District's share of the Nine Canyon Wind output. Grant PUD takes delivery of the District's share of the variable output of the project, stores the energy and delivers it to BPA's transmission system for the District in whole megawatt amounts. These whole megawatt power amounts from Nine Canyon via Grant PUD and BPA transmission are netted against the District's monthly BPA deliveries.

The cost of the Nine Canyon Wind power including Grant PUD services and BPA transmission is approximately 5.4 cents per kilowatt-hour. The District anticipates offering a green power rate option for its customers in early 2003. The green power rate will be somewhat higher than the District's standard rate based upon the actual cost of Nine Canyon power. The District used a portion ($11,259) of the BPA Conservation and Renewables Discount (See Note 10) to defray a portion of the cost of the Nine Canyon Wind Power. Nine Canyon Wind power, which is not sold as green power, is melded with the District's other power supply.

**Note 9 - District Hydroelectric Projects**

**Cowlitz Falls Project** - The Cowlitz Falls Project is located on the upper Cowlitz River in eastern Lewis County, Washington upstream from two existing hydroelectric projects, Mayfield and Mossyrock, owned by the City of Tacoma. The Project includes a concrete gravity dam and powerhouse, a reservoir covering about 610 acres extending approximately 10 miles up the Cowlitz River and 1.5 miles of the Cispus River, and 5.2 miles of overland transmission line to the District's Glenoma Substation.

The powerhouse contains two Kaplan turbine generating units with net installed capacity of 35 MW each at a rated head of 87.5 feet. Average annual energy generation is estimated at 261 million kilowatt hours. Project operation depends upon the "run of the river" to produce the maximum amount of electric energy, instead of extensively regulating the reservoir behind the dam to maximize the Project's firm or dependable capacity.

In June 1986, the District was granted a license by FERC to proceed with the development and construction of the Cowlitz Falls Project. On May 23, 1991 the District and BPA executed an Amendatory Power Purchase Contract. Construction of the Project began in July 1991. The Project began commercial operation on June 29, 1994.

**Note 9 - District Hydroelectric Projects (Continued)**

Revenues for the Cowlitz Falls System are recognized on the basis of the Amendatory Power Purchase Contract between the District and BPA. Through this contract BPA receives all output from the Cowlitz Falls Project in exchange for payment of all operating and maintenance costs and debt service on Cowlitz Falls revenue bonds (See Note 12). The District receives monthly operation and maintenance payments from BPA based upon an annual budget of operating and capital project expenditures. Certain operating and maintenance costs are subject to incentive or reimbursement provisions if actual expenses are less or more than certain budgeted amounts. The district did not receive any incentive payments for the year ended December 31, 2002. Debt service payments are made by BPA directly to the Bond transfer agent for payment of scheduled bond interest and principal.

The District records the Cowlitz Falls System activity reflecting the cost reimbursement basis of the Amendatory Power Purchase Contract with BPA. As a result, revenues and costs offset one another with no resulting net income or loss. The Cowlitz Falls System consists of essentially two activities, plant construction and related debt service and operations and maintenance. For related debt service, revenue is recognized primarily for BPA debt service payments and interest income on the reserve fund (See Note 3). Expenses consist of interest on the outstanding revenue bonds, depreciation and amortization of bond costs. For operations and maintenance, revenue is recognized primarily for BPA operation and maintenance advances and interest income on unspent advances. Expenses consist of operation and maintenance costs, including plant renewals and replacements, and taxes.

As part of the contract, the District (Electric System) provides power transmission services to BPA over facilities of both the City of Tacoma and the District. The terms and conditions for the use of the Tacoma facilities are governed by an agreement between Tacoma and the District. Costs are passed to BPA as part of the District's contract with BPA. The contract with BPA calls for monthly payments adjusted annually and expires no earlier than June 2012. After June 2012, the contract contains termination and extension provisions. Revenue amounted to $410,618 and $928,032 for the years ended December 31, 2002 and 2001, respectively. As a result of an audit of the transmission services, an overpayment of $410,031 was identified for the years 1994 through 2001. The District and BPA agreed to a reimbursement of the overpayment through a reduction in the monthly payments for transmission service for the period October 2001 through September 2002.

**Mill Creek Hydroelectric Project -** The Mill Creek Hydroelectric Project is located on Mill Creek, a tributary to the Cowlitz River, near Salkum, Washington and the Cowlitz Salmon Hatchery. The project includes a six foot high concrete diversion structure, 1,500 feet of 42 inch concrete cylinder pipe and a concrete block powerhouse downstream. The powerhouse contains two Francis turbine induction generating units with net installed capacity of 300 KW each at an average head of 96 feet. The Project generated 968,400 and 1,104,000 kilowatt hours of energy for the years ended December 31, 2002 and 2001, respectively.

**Note 10 - Conservation Programs**

The District operates energy conservation programs primarily involving the weatherization of residential dwellings and commercial property. In 1996, the District initiated a low interest loan program to fund conservation including weatherization, heat pumps and commercial energy efficiency. The initial loans were unsecured but beginning in 2000 the District began securing loans with property liens. Total loans outstanding were $850,841 and $1,019,995 at December 31, 2002 and 2001, respectively. Total expenditures for all conservation programs, including administration, were as follows:

| | 2002 | 2001 |
|---|---|---|
| Other District programs | $ 141,347 | $ 212,589 |
| Loan program disbursements and expenses, net of repayments and interest | (104,515) | 100,610 |
| Reimbursements | (230,566) | (274,720) |
| | $ (193,734) | $ 38,479 |

Beginning October 1, 2001, the District initiated an expanded five year conservation program known as "The Conservation and Renewables Discount Program." The program provides incentives for measures in the residential, commercial and industrial sectors. Funding for the program is provided by a BPA rate discount of 0.5 mills per KWH which commenced October 1, 2001. At the conclusion of the five year program period, the District must remit any unspent funds to the BPA. Management intends to fully expend the funds on qualifying conservation measures.

**Note 11 - PURMS Self-Insurance Agreement**

The District and sixteen other PUD's participate in a joint self-insurance pool (Fund) in affiliation with Public Utility Risk Management Services (PURMS) formerly Washington Public Utility Districts' Utilities System (WPUDUS).

**Liability risk pool** - PURMS provides liability insurance coverage for its members participating in the Liability Risk Pool ("Liability Pool") and their employees under an agreement entitled "PURMS Joint Self-Insurance Agreement" (amended and restated as of December 7, 2001, "SIA"). Under SIA, from 1977 through 1995, the Liability Pool had a self-insured retention of $500,000 per occurrence. Effective January 1, 1996, PURMS increased the self-insured retention of its Liability Pool to $1,000,000 per occurrence.

The Liability Pool is financed through assessments of its participating members. Assessments are levied at the beginning of each calendar year to replenish the Liability Pool to its designated risk pool balance, and at any time during the year that the actual risk pool balance becomes $500,000 less than the designated risk pool balance. For calendar year 2002, the designated risk pool balance was $2,000,000.

**Note 11 - PURMS Self-Insurance Agreement (Continued)**

At all times, PURMS also maintains excess liability insurance for its members in the Liability Pool. For year 2002, the amount of such excess insurance was $35,000,000.

As of December 31, 2002, there were 217 known incidents and unresolved liability claims pending against one or more members or former members of PURMS' Liability Pool. The total dollar value of the risk posed by these claims to such members and to the Liability Pool itself is unknown. Accordingly, no provision has been included in the accompanying financial statements.

**Property risk pool** - PURMS provides property insurance for its members participating in the Property Risk Pool ("Property Pool") in accordance with the terms of the SIA (identified above). Under the SIA, from its inception in 1997 to the present, the Property Pool has had a self-insured retention of $250,000 per property loss and maintains operating capital and reserves between $250,000 and $500,000.

The Property Pool is financed through assessments of its participating members. Assessments are levied at the beginning of each calendar year to replenish the Property Pool to its designated risk pool balance, and at any time during the year that the actual risk pool balance becomes $250,000 less than its designated risk pool balance. Since 1997, the designated risk pool balance has been $500,000.

At all times, PURMS also maintains excess property insurance for its members in the Property Risk Pool. For year 2002, the amount of such excess insurance was $125,000,000.

As of December 31, 2002, there were 12 known property claims pending from the members of PURMS' Property Pool. The total dollar value of the risk posed by these claims to Property Pool is unknown. Accordingly, no provision has been included in the accompanying financial statements

**Note 12 - Cowlitz Falls Hydroelectric Project Revenue Bonds**

On September 28, 1993, the District issued $148,395,000 in Cowlitz Falls Hydroelectric Project Revenue Bonds with an average interest rate of 4.7% to advance refund $130,025,000 of outstanding 1991 Cowlitz Falls Hydroelectric Project Revenue Bonds with an average interest rate of 6.8%. The net proceeds of $145,723,000 (after payment of $2,672,000 in underwriting fees, discounts, and other issuance costs, net of a forward supply contract) plus an additional $4,516,000 of 1991 Series sinking fund monies were used to purchase U.S. government securities. Those securities were deposited in an irrevocable trust with an escrow agent to provide for all future debt service payments on the refunded 1991 Series bonds. As a result, $130,025,000 of the 1991 Series bonds are considered to be defeased and the liability for those bonds has been removed from the financial statements of the District.

**Note 12 - Cowlitz Falls Hydroelectric Project Revenue Bonds (Continued)**

The advance refunding resulted in a difference between the reacquisition price and the net carrying amount of the old debt of $20,266,000. This difference, reported as a reduction in bonds payable, is being charged to operations through the year 2022 using the effective interest method. The District completed the advance refunding to reduce its total debt service payments over the refunding term by $11,922,000 and to obtain an economic gain, measured as the difference between the present values of the old and new debt service payment requirements, of $6,055,000.

The 1991 and 1993 Cowlitz Falls Hydroelectric Project Revenue Bonds were used to provide funds for the construction of the Cowlitz Falls Hydroelectric Dam (See Note 9).

The remaining 1991 and 1993 Bonds are special limited obligations of the District secured by a lien and charge on the Cowlitz Falls revenues and money on deposit in Funds under the Bond Resolution. Pursuant to a Power Purchase Contract and Payment Agreement all Project output has been sold to BPA. BPA is obligated to pay all operation and maintenance costs including debt service on the Bonds, whether or not the Dam is operating or operable. The Bonds are redeemable in whole or in part beginning in 2001 in amounts at or exceeding par plus accrued interest.

The Bonds consist of the following:

| | 2002 | 2001 |
|---|---|---|
| 1991 Revenue Bonds | | |
| 6% Term Bonds due 2024 | $ 24,685,000 | $ 24,685,000 |
| 1993 Revenue Bonds | | |
| Serial Bonds due through 2014 (Interest from 4.625% to 5.5%) | 45,945,000 | 49,810,000 |
| 5.5% Term Bonds due 2013 | 19,285,000 | 19,285,000 |
| 5.5% Term Bonds due 2022 | 73,300,000 | 73,300,000 |
| | 138,530,000 | 142,395,000 |
| | 163,215,000 | 167,080,000 |
| Less loss on refunding, net of amortization of $9,071,044 and $8,116,985 at December 31, 2002 and 2001, respectively | 11,195,113 | 12,149,172 |
| Total | 152,019,887 | 154,930,828 |
| Less current maturities | 4,050,000 | 3,865,000 |
| Long-term portion of revenue bonds | $ 147,969,887 | $ 151,065,828 |

**Note 12 - Cowlitz Falls Hydroelectric Project Revenue Bonds (Continued)**

Scheduled debt service deposits for principal, interest and principal maturities are as follows:

| | SINKING FUNDS | | | |
|---|---|---|---|---|
| | INTEREST | PRINCIPAL | TOTAL | PRINCIPAL MATURITIES |
| 2003 | $ 9,004,105 | $ 4,050,000 | $ 13,054,105 | $ 4,050,000 |
| 2004 | 8,806,668 | 4,245,000 | 13,051,668 | 4,245,000 |
| 2005 | 8,594,418 | 4,460,000 | 13,054,418 | 4,460,000 |
| 2006 | 8,365,843 | 4,690,000 | 13,055,843 | 4,690,000 |
| 2007 | 8,121,963 | 4,930,000 | 13,051,963 | 4,930,000 |
| Thereafter | 81,877,511 | 140,840,000 | 222,717,511 | 140,840,000 |
| | $ 124,770,508 | $ 163,215,000 | $ 287,985,508 | $ 163,215,000 |

**Special Funds - Cowlitz Falls Hydroelectric Project**

**Sinking Funds** - Bond resolutions require the establishment and maintenance of bond principal, interest and reserve sinking fund accounts, the purpose of which is to provide additional security as well as scheduled debt service payments. Sinking funds are recorded as special funds in other property and investments.

**Note 13 - Electric System Revenue Bonds, Series 1992**

The District issued $9,499,000 in Revenue Bonds in June 1992 for financing a portion of the District's Capital Improvement Program and conservation efforts. The Program made capital improvements and completed conservation efforts of $13 million over a two year period.

On November 29, 1994, the District deposited $9,480,300 in an irrevocable trust with an escrow agent to provide for all future debt service payments on the 1992 Series bonds. As a result, the 1992 Series bonds are considered defeased and the liability for those bonds have been removed from the financial statements of the District. This defeasance resulted in an accounting loss of approximately $420,000 which was capitalized to utility plant.

**Note 14 - Fair Value of Financial Instruments**

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value:

**Other property, investments and cash** - The fair values of these items are estimated based on quoted market prices for the same or similar investments. The District's investment vehicles are limited to deposits with Washington State banks or obligations of the U.S. government (See Note 3).

**Long-term debt** - The fair value of the District's long-term debt is estimated based on the quoted market prices for the same or similar issues.

| | DECEMBER 31, 2002 | | DECEMBER 31, 2001 | |
|---|---|---|---|---|
| | Principal Amount | Fair Value | Principal Amount | Fair Value |
| LONG-TERM DEBT | | | | |
| 91 Revenue bonds | $ 24,685,000 | $ 24,872,853 | $ 24,685,000 | $ 25,024,912 |
| 93 Revenue bonds | 138,530,000 | 142,508,436 | 142,395,000 | 145,443,966 |
| | $ 163,215,000 | $ 167,381,289 | $ 167,080,000 | $ 170,468,878 |

**Note 15 - Endangered Species Listing of Salmon and Steelhead/American Rivers Intent to Sue**

The National Marine Fisheries Service (NMFS) has listed the lower Columbia Chinook salmon and steelhead trout as threatened under the Endangered Species Act (ESA). The Cowlitz River is a tributary of the lower Columbia River and the Cowlitz Falls Project operates on the Cowlitz. As a result of the Cowlitz Falls operation and the ESA anadromous fish listings, the District has initiated consultation with the FERC and NMFS to evaluate possible ESA impacts on the Project. This consultation is expected to lead toward a permitted taking of the threatened species for the Project. This process will likely result in certain undetermined costs related to Project operation and mitigation provisions.

On January 14, 2000, American Rivers, Trout Unlimited and Friends of the Cowlitz filed a Notice of Intent to Sue for Violations of the ESA. The Notice claims the FERC, BPA and District are violating the ESA by continued operation of the Cowlitz Falls Project. American Rivers indicates that unless BPA and FERC initiate consultation under Section 7 of the ESA with NMFS regarding the impact of the Project on listed species and unless immediate action is taken to bring the Project into compliance, they will file suit against the FERC, BPA and District. Should American Rivers file suit, the Project could experience added costs associated with the District's defense.

As stated in Note 9, BPA pays all operating and maintenance costs of the Cowlitz Falls Project. As such, the above matters are not expected to impact the District's financial position.

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# APPENDIX G

## XL CAPITAL ASSURANCE SPECIMEN POLICY

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XL CAPITAL ASSURANCE

1221 Avenue of the Americas
New York, New York 10020
Telephone: (212) 478-3400

# MUNICIPAL BOND INSURANCE POLICY

**ISSUER:** [ ] **Policy No:** [ ]

**BONDS:** [ ] **Effective Date:** [ ]

**XL Capital Assurance Inc. (XLCA),** a New York stock insurance company, in consideration of the payment of the premium and subject to the terms of this Policy (which includes each endorsement attached hereto), hereby agrees unconditionally and irrevocably to pay to the trustee (the "Trustee") or the paying agent (the "Paying Agent") (as set forth in the documentation providing for the issuance of and securing the Bonds) for the benefit of the Owners of the Bonds or, at the election of XLCA, to each Owner, that portion of the principal and interest on the Bonds that shall become Due for Payment but shall be unpaid by reason of Nonpayment.

XLCA will pay such amounts to or for the benefit of the Owners on the later of the day on which such principal and interest becomes Due for Payment or one (1) Business Day following the Business Day on which XLCA shall have received Notice of Nonpayment (provided that Notice will be deemed received on a given Business Day if it is received prior to 10:00 a.m. New York time on such Business Day; otherwise it will be deemed received on the next Business Day), but only upon receipt by XLCA, in a form reasonably satisfactory to it, of (a) evidence of the Owner's right to receive payment of the principal or interest then Due for Payment and (b) evidence, including any appropriate instruments of assignment, that all of the Owner's rights with respect to payment of such principal or interest that is Due for Payment shall thereupon vest in XLCA. Upon such disbursement, XLCA shall become the owner of the Bond, any appurtenant coupon to the Bond or the right to receipt of payment of principal and interest on the Bond and shall be fully subrogated to the rights of the Owner, including the Owner's right to receive payments under the Bond, to the extent of any payment by XLCA hereunder. Payment by XLCA to the Trustee or Paying Agent for the benefit of the Owners shall, to the extent thereof, discharge the obligation of XLCA under this Policy.

In the event the Trustee or Paying Agent has notice that any payment of principal or interest on a Bond which has become Due for Payment and which is made to an Owner by or on behalf of the Issuer of the Bonds has been recovered from the Owner pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such Owner within the meaning of any applicable bankruptcy law, such Owner will be entitled to payment from XLCA to the extent of such recovery if sufficient funds are not otherwise available.

The following terms shall have the meanings specified for all purposes of this Policy, except to the extent such terms are expressly modified by an endorsement to this Policy. "Business Day" means any day other than (a) a Saturday or Sunday or (b) a day on which banking institutions in the State of New York or the Insurer's Fiscal Agent are authorized or required by law or executive order to remain closed. "Due for Payment", when referring to the principal of Bonds, is when the stated maturity date or a mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity, unless XLCA shall elect, in its sole discretion, to pay such principal due upon such acceleration; and, when referring to interest on the Bonds, is when the stated date for payment of interest has been reached. "Nonpayment" means the failure of the Issuer to have provided sufficient funds to the Trustee or Paying Agent for payment in full of all principal and interest on the Bonds which are Due for Payment. "Notice" means telephonic or telecopied notice, subsequently confirmed in a signed writing, or written notice by registered or certified mail, from an Owner, the Trustee or the Paying Agent to XLCA which notice shall specify (a) the person or entity making the claim, (b) the Policy Number, (c) the claimed amount and (d) the date such claimed amount became Due for Payment. "Owner" means, in respect of a Bond, the person or entity who, at the time of Nonpayment, is entitled under the terms of such Bond to payment thereof, except that "Owner" shall not include the Issuer or any person or entity whose direct or indirect obligation constitutes the underlying security for the Bonds.

XLCA may, by giving written notice to the Trustee and the Paying Agent, appoint a fiscal agent (the "Insurer's Fiscal Agent") for purposes of this Policy. From and after the date of receipt by the Trustee and the Paying Agent of such notice, which shall specify the name and notice address of the Insurer's Fiscal Agent, (a) copies of all notices required to be delivered to XLCA pursuant to this Policy shall be simultaneously delivered to the Insurer's Fiscal Agent and to XCLA and shall not be deemed received until received by both and (b) all payments required to be made by XLCA under this Policy may be made directly by XLCA or by the Insurer's Fiscal Agent on behalf of XLCA. The Insurer's Fiscal Agent is the agent of XLCA only and the Insurer's Fiscal Agent shall in no event be liable to any Owner for any act of the Insurer's Fiscal Agent or any failure of XLCA to deposit or cause to be deposited sufficient funds to make payments due hereunder.

Except to the extent expressly modified by an endorsement hereto, (a) this Policy is non-cancelable by XLCA, and (b) the Premium on this Policy is not refundable for any reason. This Policy does not insure against loss of any prepayment or other acceleration payment which at any time may become due in respect of any Bond, other than at the sole option of XLCA, nor against any risk other than Nonpayment. This Policy sets forth the full undertaking of XLCA and shall not be modified, altered or affected by any other agreement or instrument, including any modification or amendment thereto.

THIS POLICY IS NOT COVERED BY THE PROPERTY/CASUALTY INSURANCE SECURITY FUND SPECIFIED IN ARTICLE 76 OF THE NEW YORK INSURANCE LAW.

In witness whereof, XLCA has caused this Policy to be executed on its behalf by its duly authorized officers.



| | |
|---|---|
| Name: | Name: |
| Title: | Title: |

XLCAP-005
Form of Municipal Policy [Specimen]

# APPENDIX H

## MBIA INSURANCE CORPORATION SPECIMEN POLICY

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# FINANCIAL GUARANTY INSURANCE POLICY

## MBIA Insurance Corporation
## Armonk, New York 10504

Policy No. [NUMBER]

MBIA Insurance Corporation (the "Insurer"), in consideration of the payment of the premium and subject to the terms of this policy, hereby unconditionally and irrevocably guarantees to any owner, as hereinafter defined, of the following described obligations, the full and complete payment required to be made by or on behalf of the Issuer to [PAYING AGENT/TRUSTEE] or its successor (the "Paying Agent") of an amount equal to (i) the principal of (either at the stated maturity or by any advancement of maturity pursuant to a mandatory sinking fund payment) and interest on, the Obligations (as that term is defined below) as such payments shall become due but shall not be so paid (except that in the event of any acceleration of the due date of such principal by reason of mandatory or optional redemption or acceleration resulting from default or otherwise, other than any advancement of maturity pursuant to a mandatory sinking fund payment, the payments guaranteed hereby shall be made in such amounts and at such times as such payments of principal would have been due had there not been any such acceleration); and (ii) the reimbursement of any such payment which is subsequently recovered from any owner pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such owner within the meaning of any applicable bankruptcy law. The amounts referred to in clauses (i) and (ii) of the preceding sentence shall be referred to herein collectively as the "Insured Amounts." "Obligations" shall mean:

**[PAR]**
**[LEGAL NAME OF ISSUE]**

Upon receipt of telephonic or telegraphic notice, such notice subsequently confirmed in writing by registered or certified mail, or upon receipt of written notice by registered or certified mail, by the Insurer from the Paying Agent or any owner of an Obligation the payment of an Insured Amount for which is then due, that such required payment has not been made, the Insurer on the due date of such payment or within one business day after receipt of notice of such nonpayment, whichever is later, will make a deposit of funds, in an account with U.S. Bank Trust National Association, in New York, New York, or its successor, sufficient for the payment of any such Insured Amounts which are then due. Upon presentment and surrender of such Obligations or presentment of such other proof of ownership of the Obligations, together with any appropriate instruments of assignment to evidence the assignment of the Insured Amounts due on the Obligations as are paid by the Insurer, and appropriate instruments to effect the appointment of the Insurer as agent for such owners of the Obligations in any legal proceeding related to payment of Insured Amounts on the Obligations, such instruments being in a form satisfactory to U.S. Bank Trust National Association, U.S. Bank Trust National Association shall disburse to such owners, or the Paying Agent payment of the Insured Amounts due on such Obligations, less any amount held by the Paying Agent for the payment of such Insured Amounts and legally available therefor. This policy does not insure against loss of any prepayment premium which may at any time be payable with respect to any Obligation.

As used herein, the term "owner" shall mean the registered owner of any Obligation as indicated in the books maintained by the Paying Agent, the Issuer, or any designee of the Issuer for such purpose. The term owner shall not include the Issuer or any party whose agreement with the Issuer constitutes the underlying security for the Obligations.

Any service of process on the Insurer may be made to the Insurer at its offices located at 113 King Street, Armonk, New York 10504 and such service of process shall be valid and binding.

This policy is non-cancellable for any reason. The premium on this policy is not refundable for any reason including the payment prior to maturity of the Obligations.

IN WITNESS WHEREOF, the Insurer has caused this policy to be executed in facsimile on its behalf by its duly authorized officers, this [DAY] day of [MONTH, YEAR].

**MBIA Insurance Corporation**

SPECIMEN

____________________________
President

Attest: ____________________________
Assistant Secretary

STD-R-6
4/95

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