NEW ISSUE — BOOK-ENTRY ONLY

Series 2004-A Bonds and Columbia 2004-C Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, based on an analysis of existing laws, regulations, rulings and court decisions and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, (a) interest on the Series 2004-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and (b) interest on the Columbia 2004-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act and Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2004-A Bonds and on the Columbia 2004-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. See "TAX MATTERS" herein.

Series 2004-B (Taxable) Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2004-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the 1986 Code. See "TAX MATTERS" herein.

$610,655,000

Energy Northwest

$62,485,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-A
$422,350,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A
$83,835,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-A

$1,135,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)
$12,715,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2004-B (Taxable)
$1,515,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)

$26,620,000 Columbia Generating Station Electric Revenue Bonds, Series 2004-C

Dated: Date of delivery **Due: July 1, as shown on the inside cover**

The Series 2004-A and the Series 2004-B (Taxable) Bonds are being issued for the purpose of refunding Prior Lien Bonds and Electric Revenue Bonds heretofore issued by Energy Northwest in connection with Project 1, Columbia and Project 3, as more fully described herein. The Columbia 2004-C Bonds and a portion of the Columbia 2004-B Bonds are being issued to finance a portion of the costs of certain capital improvements at the Columbia Generating Station. See "PURPOSE OF ISSUANCE" herein.

The 2004 Bonds will be issued in fully registered form, registered in the name of Cede & Co., as Registered Owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2004 Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the Registered Owner of the 2004 Bonds and nominee of DTC, references herein to holders or Registered Owners shall mean Cede & Co. and shall not mean the beneficial owners of the 2004 Bonds. Principal of the 2004 Bonds is payable at the principal office of BNY Western Trust Company, Seattle, Washington, as Trustee for the 2004 Bonds. Interest on the Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2005, by check or draft of the Trustee. As long as Cede & Co. is the Registered Owner as nominee of DTC, payments on the 2004 Bonds will be made to such Registered Owner, and disbursement of such payments will be the responsibility of DTC and DTC participants as described herein. See "DESCRIPTION OF THE 2004 BONDS – GENERAL — Book Entry Only System; Transferability and Registration" and Appendix I — "BOOK-ENTRY ONLY SYSTEM" herein.

*Certain of the Series 2004-A Bonds and the Columbia 2004-C Bonds are subject to redemption prior to maturity as set forth herein. The Series 2004-B (Taxable) Bonds are not subject to redemption prior to maturity. See "*DESCRIPTION OF THE 2004 BONDS — REDEMPTION*" herein.*

The 2004 Bonds are special revenue obligations of Energy Northwest, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the

Bonneville Power Administration

from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The 2004 Bonds are payable as provided herein on a subordinated basis to the Prior Lien Bonds and do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power. Projects 1 and 3 and Columbia are separate projects of Energy Northwest and each Series of 2004 Bonds is payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A — "THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover

The 2004 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Preston Gates & Ellis LLP, Seattle, Washington, Bond Counsel to Energy Northwest, and to certain other conditions. Certain tax matters will be passed upon by Orrick Herrington & Sutcliffe, LLP, Special Tax Counsel. Certain legal matters will be passed upon for Energy Northwest by its General Counsel and for Bonneville by its General Counsel and by its Special Counsel, Orrick Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters. It is expected that the 2004 Bonds will be available for delivery through the facilities of DTC on or about June 2, 2004.

Goldman, Sachs & Co. **Citigroup**

JPMorgan **Prager, Sealy & Co., LLC** **UBS Financial Services Inc.**

May 21, 2004

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES AND YIELDS

THE SERIES 2004-A BONDS

$62,485,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013†	$62,485,000	5¼%	4.30%	29270CHK4

$422,350,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2008	$77,870,000	5¼%	3.28%	29270CHL2
2008	6,400,000	3¾	3.28	29270CHM0
2009††	69,225,000	5¼	3.53	29270CHN8
2010†††	90,860,000	5¼	3.79	29270CHP3
2011††	38,735,000	5¼	3.99	29270CHQ1
2011	10,000,000	5¼	4.05	29270CHR9
2017†	20,375,000	5¼	4.59	29270CHS7
2018†	88,885,000	5¼	4.72[1]	29270CHT5
2018	20,000,000	5¼	4.78[1]	29270CHU2

$83,835,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2014†	$26,490,000	5¼%	4.42%	29270CHV0
2015†	26,535,000	5¼	4.54[1]	29270CHW8
2016†	30,810,000	5¼	4.56	29270CHX6

THE SERIES 2004-B (TAXABLE) BONDS

$1,135,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013	$1,135,000	5½%	5.543%	29270CHY4

$12,715,000 Columbia Generating Station Electric Revenue and Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013	$12,715,000	5½%	5.543%	29270CHZ1

$1,515,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013	$1,515,000	5½%	5.543%	29270CJA4

THE COLUMBIA 2004-C BONDS

$26,620,000 Columbia Generating Station Electric Revenue Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2007	$1,690,000	5¼%	2.90%	29270CJB2
2008	1,780,000	5¼	3.28	29270CJC0
2009	1,875,000	5¼	3.59	29270CJD8
2010	1,970,000	5¼	3.85	29270CJE6
2011†	2,075,000	5¼	3.99	29270CJF3
2012†	2,185,000	5¼	4.17	29270CJG1
2013†	1,595,000	5¼	4.30	29270CJH9
2014	2,420,000	5¼	4.48	29270CJJ5
2015†	2,550,000	5¼	4.54[1]	29270CJK2
2016†	2,685,000	5¼	4.56	29270CJL0
2017†	2,825,000	5¼	4.59	29270CJM8
2018†	2,970,000	5¼	4.72[1]	29270CJN6

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1 Priced to 7/01/2014 call at par.

* CUSIP numbers have been assigned to the 2004 Bonds by an organization not affiliated with Energy Northwest and are included for the convenience of the 2004 Bondowners only. Energy Northwest is not responsible for the selection of the CUSIP numbers, nor any representation as to their correctness on the 2004 Bonds or as indicated herein.

† Insured by MBIA Insurance Corporation.

†† Insured by Ambac Assurance Corporation.

††† Insured by Financial Guaranty Insurance Company.

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Telephone (509) 372-5000
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Edward E. Coates, Chairman	Vera Claussen
Dan G. Gunkel, Vice Chairman	Tim Sheldon
Darrel Bunch, Secretary	Larry Kenney
Amy C. Solomon, Assistant Secretary	Sid W. Morrison
Margaret Allen	Roger C. Sparks
Tom Casey	

Administrative Staff

Chief Executive Officer/Chief Nuclear Officer	Joseph V. Parrish
Vice President, Nuclear Generation	Rodney L. Webring
Vice President, Technical Services	Dale K. Atkinson
Vice President, Energy/Business Services/ Public Information Officer	John W. Baker
Vice President, Corporate Services/General Counsel/Chief Financial Officer	Albert E. Mouncer
Assistant to Chief Executive Officer/Chief Knowledge Officer	Cheryl M. Whitcomb

Financial Advisor	*Bond Counsel*	*Trustee for the 2004 Bonds*
Public Financial Management, Inc.	Preston Gates & Ellis LLP	BNY Western Trust Company

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
Portland, Oregon 97208
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Administrator and Chief Executive Officer	Stephen J. Wright
Deputy Administrator and Deputy Chief Executive Officer	Steven G. Hickok
Chief Operating Officer	Ruth B. Bennett
General Counsel	Randy A. Roach
Chief Financial Officer	James H. Curtis

Special Counsel
Orrick, Herrington & Sutcliffe LLP

No dealer, broker, salesman or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations, other than as 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 Energy Northwest or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 2004 Bonds, by any person in any jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

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

Other than with respect to information concerning MBIA Insurance Corporation ("MBIA"), Ambac Assurance Corporation ("Ambac") and Financial Guaranty Insurance Company ("Financial Guaranty") contained under "SECURITY FOR NET BILLED BONDS - Bond Insurance," Appendix K-1 "MBIA Specimen Financial Guaranty Policy", Appendix K-2 "Ambac Specimen Financial Guaranty Insurance Policy" and Appendix K-3 "Financial Guaranty Specimen Municipal Bond New Issue Insurance Policy" herein, none of the information in this Official Statement has been supplied or verified by MBIA, Ambac or Financial Guaranty and none of MBIA, Ambac or FINANCIAL GUARANTY makes any representation or warranty, express or implied, as to: (i) the accuracy or completeness of such information; (ii) the validity of the 2004 Bonds, or (iii) the tax exempt status of the interest on the Series 2004-A Bonds and the Columbia Series 2004-C Bonds.

None of the information herein was provided by the Participants or the Trustee and none of such entities participated in the preparation of this Official Statement. This Official Statement has not been submitted to such entities for review, comment or approval.

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

The prospective financial information included in this Official Statement, including any forward-looking or prospective financial information, has been prepared by, and is the responsibility of the management of Energy Northwest and Bonneville. PricewaterhouseCoopers LLP has neither examined nor compiled such prospective financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP reports included in this Official Statement relate to the historical financial information of the Energy Northwest projects and Bonneville. They do not extend to the prospective financial information and should not be read to do so.

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

IN CONNECTION WITH THE OFFERING OF THE 2004 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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$610,655,000

ENERGY NORTHWEST

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$422,350,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A

$83,835,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-A

$1,135,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)

$12,715,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2004-B (Taxable)

$1,515,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)

$26,620,000 Columbia Generating Station Electric Revenue Bonds, Series 2004-C

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of the 2004 Bonds (hereinafter defined).

This Introduction is not intended to provide all information material to a prospective purchaser of the 2004 Bonds and is qualified in all respects by the more detailed information set forth elsewhere in this Official Statement. Unless otherwise specifically defined, certain capitalized terms used in this Introduction have the meanings given to such terms elsewhere in this Official Statement.

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington (formerly known as the Washington Public Power Supply System), proposes to issue $62,485,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-A (the "Project 1 2004-A Bonds"), $422,350,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A (the "Columbia 2004-A Bonds"), $83,835,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-A (the "Project 3 2004-A Bonds", and together with the Project 1 2004-A Bonds and the Columbia 2004-A Bonds, the "Series 2004-A Bonds"), $1,135,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable) (the "Project 1 2004-B (Taxable) Bonds"), $12,715,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2004-B (Taxable) (the "Columbia 2004-B (Taxable) Bonds"), $1,515,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable) (the "Project 3 2004-B (Taxable) Bonds", and together with the Project 1 2004-B (Taxable) Bonds and the Columbia 2004-B (Taxable) Bonds, the "Series 2004-B (Taxable) Bonds") and $26,620,000 Columbia Generating Station Electric Revenue Bonds, Series 2004-C (the "Columbia 2004-C Bonds"). The Series 2004-A Bonds, Series 2004-B (Taxable) Bonds and Columbia 2004-C Bonds are together referred to herein as the "2004 Bonds."

The Project 1 2004-A Bonds are being issued pursuant to Chapters 39.46, 39.53 and 43.52 of the Revised Code of Washington, as amended (the "Act") and Resolution No. 835, adopted on November 23, 1993 (as amended and supplemented, the "Project 1 Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness of Energy Northwest, including certain indebtedness currently outstanding under Resolution No. 769, adopted September 18, 1975 (as amended and supplemented the "Project 1 Prior Lien Resolution") and certain indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution. The Project 1 2004-B (Taxable) Bonds (together with the Project 1 2004-A Bonds, the "Project 1 2004 Bonds") are being issued pursuant to the Act and the Project 1 Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the Project 1 2004 Bonds. Bonds issued pursuant to the Project 1 Prior Lien Resolution are referred to herein as the "Project 1 Prior Lien Bonds" and bonds issued pursuant to the Project 1 Electric Revenue Bond Resolution are referred to herein as the "Project 1 Electric Revenue Bonds."

The Columbia 2004-A Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted on October 23, 1997 (as amended and supplemented, the "Columbia Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness of Energy Northwest, including indebtedness currently outstanding under Resolution No. 640, adopted June 26, 1973 (as amended and supplemented, the "Columbia Prior Lien Resolution") and certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution. The Columbia 2004-B (Taxable) Bonds are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the

Columbia 2004-A Bonds and the Columbia 2004-B (Taxable) Bonds and to finance a portion of the cost of certain capital improvements at the hereinafter defined Columbia Generating Station. The Columbia 2004-C Bonds (together with the Columbia 2004-A Bonds and the Columbia 2004-B (Taxable) Bonds, the "Columbia 2004 Bonds") are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution to finance a portion of the cost of certain capital improvements at the Columbia Generating Station and to pay certain costs of issuance related to the Columbia 2004-C Bonds. Bonds issued pursuant to the Columbia Prior Lien Resolution are referred to herein as the "Columbia Prior Lien Bonds" and bonds issued pursuant to the Columbia Electric Revenue Bond Resolution are referred to herein as the "Columbia Electric Revenue Bonds."

The Project 3 2004-A Bonds are being issued pursuant to the Act and Resolution No. 838 adopted on November 23, 1993 (as amended and supplemented, the "Project 3 Electric Revenue Bond Resolution," and together with the Project 1 Electric Revenue Bond Resolution and the Columbia Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions") for the purpose of refunding certain indebtedness of Energy Northwest, including certain indebtedness currently outstanding under Resolution No. 775, adopted on December 3, 1975 (as amended and supplemented, the "Project 3 Prior Lien Resolution", and together with the Project 1 Prior Lien Resolution and the Columbia Prior Lien Resolution, the "Prior Lien Resolutions"). The Project 3 2004-B (Taxable) Bonds (together with the Project 3 2004-A Bonds, the "Project 3 2004 Bonds") are being issued pursuant to the Act and the Project 3 Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the Project 3 2004 Bonds. Bonds issued pursuant to the Project 3 Prior Lien Resolution are referred to herein as the "Project 3 Prior Lien Bonds," and together with the Project 1 Prior Lien Bonds and the Columbia Prior Lien Bonds are collectively referred to herein as the "Prior Lien Bonds." Bonds issued pursuant to the Project 3 Electric Revenue Bond Resolution are referred to herein as the "Project 3 Electric Revenue Bonds," and together with the Project 1 Electric Revenue Bonds and the Columbia Electric Revenue Bonds are collectively referred to herein as the "Electric Revenue Bonds."

The Prior Lien Bonds, the Electric Revenue Bonds, including the 2004 Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Subordinated Resolutions are collectively referred to herein as the "Net Billed Bonds."

For additional information relating to the indebtedness to be refunded and other purposes of issuance, see "PURPOSE OF ISSUANCE" in this Official Statement.

ENERGY NORTHWEST

Energy Northwest was organized in 1957 as the Washington Public Power Supply System. By resolution of its Executive Board adopted on June 2, 1999, the Washington Public Power Supply System officially changed its name to Energy Northwest. It currently has 18 members, consisting of 15 public utility districts and the cities of Richland, Seattle and Tacoma, all located in the State of Washington. Energy Northwest has the authority, among other things, to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power and energy and to issue bonds and other evidences of indebtedness to finance the same.

Energy Northwest owns and operates a nuclear electric generating station, the Columbia Generating Station ("Columbia Generating Station" or "Columbia"), formerly known as Nuclear Project No. 2, with a net design electric rating of 1,153 megawatts. Energy Northwest also owns an operating hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), with a name-plate rating of 27.5 megawatts. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 49 turbines with a maximum generating capacity of approximately 64 megawatts. Energy Northwest also owns and/or has financial responsibility for four other nuclear electric generating projects which have been terminated: Energy Northwest Nuclear Project No. 1 ("Project 1"), Energy Northwest Nuclear Project No. 3 ("Project 3") and Energy Northwest Nuclear Projects Nos. 4 and 5 ("Projects 4 and 5"). Energy Northwest also owns the Hanford Generating Project ("HGP"), which ceased operation in 1987, but site restoration activities coordinated with the United States Department of Energy ("DOE") are continuing. Projects 1 and 3 were terminated in 1994 and Projects 4 and 5 were terminated in 1982. For discussions concerning the termination of Projects Nos. 1, 3, 4 and 5, see "ENERGY NORTHWEST — PROJECT 1," "— PROJECT 3," and "— PROJECTS 4 and 5" in this Official Statement. Projects 1 and 3 and Columbia are collectively referred to herein as the "Net Billed Projects." Each of Projects 1 and 3 and Columbia is financed and accounted for as a separate utility system. Projects 4 and 5 were financed and accounted for as a single utility system separate and apart from all other Energy Northwest projects. All of Energy Northwest's projects are located in the State of Washington. For additional information relating to Energy Northwest, see "ENERGY NORTHWEST" in this Official Statement.

The United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), has acquired the capability of Projects 1 and 3 and Columbia. As more fully discussed under "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS," Bonneville pays Energy Northwest for such capability pursuant to Net Billing Agreements (hereinafter defined), with payments being made through a combination of credits against customer bills and cash payments from the Bonneville Fund (hereinafter defined). Bonneville's obligations to make such payments under the Net Billing Agreements continue notwithstanding suspension or termination of any of Projects 1 or 3 or Columbia.

THE BONNEVILLE POWER ADMINISTRATION

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

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

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

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

THE 2004 BONDS

The Project 1 2004 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2004 Bonds are secured on a subordinated basis to the Project 1 Prior Lien Bonds which are outstanding under the Project 1 Prior Lien Resolution by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2004 Bonds are secured on parity with Project 1 Electric Revenue Bonds which are outstanding pursuant to the Project 1 Electric Revenue Bond Resolution and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Subordinated Resolution.

The Columbia 2004 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2004 Bonds are secured on a subordinated basis to the Columbia Prior Lien Bonds which are outstanding under the Columbia Prior Lien Resolution by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership and operation of Columbia. The Columbia 2004 Bonds are secured on parity with the Columbia Electric Revenue Bonds which are outstanding pursuant to the Columbia Electric Revenue Bond Resolution and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Subordinated Resolution.

The Project 3 2004 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2004 Bonds are secured on a subordinated basis to the Project 3 Prior Lien Bonds which are outstanding under the Project 3 Prior Lien Resolution by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2004 Bonds are secured on parity with the Project 3 Electric Revenue Bonds which are outstanding pursuant to the Project 3 Electric Revenue Bond Resolution and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Subordinated Resolution.

There are no restrictions under the Electric Revenue Bond Resolutions on the issuance of debt pursuant to any of the above mentioned Separate Subordinated Resolutions, other than the Net Billing Agreements and the other Project agreements being in effect and no event of default is existing under the applicable Electric Revenue Bond Resolution. See "SECURITY FOR THE NET BILLED BONDS — ADDITIONAL INDEBTEDNESS" in this Official Statement.

Energy Northwest has covenanted that it will not issue any more Prior Lien Bonds or any other bonds, warrants or other obligations which will rank on a parity with the pledge of and lien on the revenues created by the related Prior Lien Resolution.

The 2004 Bonds are secured on a subordinated basis to the Prior Lien Bonds from amounts derived pursuant to Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The receipts, income and revenues derived from a Project secure only the related Series 2004-A Bonds, Series

2004-B (Taxable) Bonds or the Columbia 2004-C Bonds, respectively. Accordingly, the owners of the 2004 Bonds issued for a particular Project will have no claim on the receipts, income and revenues securing any other Energy Northwest Project.

For further information, see "SECURITY FOR THE NET BILLED BONDS" in this Official Statement. For further information on the Net Billed Bonds outstanding as of May 1, 2004, see "ENERGY NORTHWEST-ENERGY NORTHWEST INDEBTEDNESS" in this Official Statement.

NET BILLING AGREEMENTS

Under the Net Billing Agreements, the Participants in each Net Billed Project have contracted to purchase the capability of that Net Billed Project and have agreed to provide Energy Northwest with funds necessary to meet costs of that Net Billed Project. These costs include the amounts that Energy Northwest is obligated to pay in each contract year into the various funds provided for in the Prior Lien Resolution and Electric Revenue Bond Resolution related to such Net Billed Project for debt service and for all other purposes of the Net Billed Project. The Net Billing Agreements also effected a simultaneous assignment of the Project capability from the Participants to Bonneville and created an obligation of Bonneville to pay the Participants (from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund, as described herein) for their respective shares of the costs of the Net Billed Projects. Thus, Bonneville is ultimately obligated to meet such costs.

Under the Net Billing Agreements, payments to Energy Northwest are not made directly by Bonneville, but rather by the Participants. Such payments by the Participants are to be made in accordance with each Participant's participation in the purchase of the capability of the Net Billed Project. Bonneville pays for the capability of the Net Billed Project assigned by the Participants to it by crediting (or net billing) Bonneville's bills to Participants for power and other services purchased from Bonneville by the amount of the payment required to be made by the Participants to Energy Northwest. To the extent that the total amount of Bonneville's bills to each Participant (and consequently the amount of such credit available) over a contract year (July 1 to June 30) is less than the payment required to be made by the Participant to Energy Northwest, Bonneville is obligated to pay the deficiency in cash to the Participant from the Bonneville Fund. 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 payment obligations of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. Net proceeds 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.

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 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.

Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.

For further information as to the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS," "LEGAL MATTERS" and Appendix G — "SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS" in this Official Statement. For information with respect to Bonneville, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION."

DESCRIPTION OF THE 2004 BONDS

GENERAL

The 2004 Bonds will initially be dated the date of delivery and will mature on July 1 in the years and bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2005, at the rates shown on the inside cover of this Official Statement. Interest on the 2004 Bonds will be calculated based on a 360-day year, consisting of twelve 30 day months. BNY Western Trust Company, Seattle, Washington, has been appointed the Trustee, Paying Agent and Registrar for the 2004 Bonds (collectively, the "Trustee"). For so long as the 2004 Bonds are registered in the name of Cede & Co. (as nominee of The Depository Trust Company, New York, New York ("DTC")) or its registered assigns, payments of principal and interest shall be made in accordance with the operational arrangements of DTC. In the event that the 2004 Bonds are no longer registered in the name of Cede & Co., interest on the 2004 Bonds is payable by check or draft mailed to the Registered Owners thereof by the Trustee at the addresses appearing on the registration books on the 15th day of the month preceding the interest payment date. Principal of the 2004 Bonds is payable at the office of the Trustee in Seattle, Washington; provided, however, that upon the written request of a Registered Owner of at least $1,000,000 in aggregate principal amount of a Series of the 2004 Bonds outstanding delivered to the Trustee, interest will be paid by wire transfer on the date due to an account with a bank located in the United States.

Book-Entry Only System; Transferability and Registration

The 2004 Bonds will be available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the 2004 Bonds will not receive certificates representing their interests in such 2004 Bonds purchased, except as described in Appendix I — "BOOK-ENTRY ONLY SYSTEM." DTC will act as securities depository ("Securities Depository") for each Series of 2004 Bonds. As discussed in Appendix I — "BOOK-ENTRY ONLY SYSTEM," transfers of ownership interests in the 2004 Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the 2004 Bonds. Energy Northwest, the Trustee and any other person may treat the Registered Owner of any 2004 Bond as the absolute owner of such 2004 Bond for the purpose of making payment thereof and for all other purposes and Energy Northwest and the Trustee shall not be bound by any notice or knowledge to the contrary, whether such 2004 Bond shall be overdue or not. All payments of or on account of interest or principal to any Registered Owner of any such 2004 Bond shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such 2004 Bond, to the extent of the sum or sums paid.

When 2004 Bonds are registered in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Trustee shall have no responsibility or obligation to any Participant (as defined in Appendix I — "BOOK-ENTRY ONLY SYSTEM") or to any person on behalf of whom a Participant holds an interest in the 2004 Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any Participant with respect to any ownership interest in the 2004 Bonds, (2) the delivery to any Participant or any other person, other than a Registered Owner as shown on the Bond Register, of any notice with respect to the 2004 Bonds, including any notice of redemption, (3) the payment to any Participant or any other person, other than a Registered Owner as shown on the bond register, of any amount with respect to principal of, premium, if any, or interest on the 2004 Bonds, (4) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the 2004 Bonds, (5) any consent given or action taken by DTC as Registered Owner, or (6) any other matter. Energy Northwest and the Trustee may treat and consider Cede & Co., in whose name each 2004 Bond is registered, as the holder and absolute owner of such 2004 Bond for the purpose of payment, giving notices of redemption and other matters.

Discontinuation of Book-Entry Transfer System

If Energy Northwest has determined to discontinue the book-entry system of transfer, Energy Northwest shall execute, authenticate and deliver at no cost to the beneficial owners of the 2004 Bonds, 2004 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2004 Bonds shall be payable upon due presentment and surrender thereof at the principal office of the Trustee and interest on the 2004 Bonds will be payable by check or draft mailed to the persons in whose names such 2004 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date. If the book-entry transfer system for the 2004 Bonds is discontinued, registered ownership of any 2004 Bond may be transferred or exchanged by surrendering such Bond to the Trustee, with the assignment form appearing on the Bond duly executed. The Trustee shall not be required to transfer any 2004 Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

The Project 1 2004 Bonds are not subject to redemption prior to maturity.

The Columbia 2004-C Bonds maturing on July 1, 2015 and the Columbia 2004-A Bonds and the Columbia 2004-C Bonds maturing on July 1, 2018 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2014, in whole or in part at any time (in such order of maturity as is selected by Energy Northwest and within a maturity in such manner as DTC or the Trustee, as appropriate, shall determine) at a redemption price equal to the principal amount of such Bonds to be redeemed, together with accrued interest to the redemption date.

The Project 3 2004-A Bonds maturing on July 1, 2015 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2014, in whole or in part at any time (in such order of maturity as is selected by Energy Northwest and within a maturity in such manner as DTC or the Trustee, as appropriate, shall determine) at a redemption price equal to the principal amount of such Bonds to be redeemed, together with accrued interest to the redemption date.

The Series 2004-B (Taxable) Bonds are not subject to redemption prior to maturity.

Notice of Redemption

Notice of redemption of any Series of the 2004 Bonds is to be given by the Trustee by first-class mail not less than 30 days nor more than 60 days before the redemption date to the Registered Owners of the 2004 Bonds which are to be redeemed at their last addresses shown on the registration books for the 2004 Bonds. Such notice shall be deemed conclusively to be received by the Registered Owners of the 2004 Bonds which are to be redeemed, whether or not such notice is actually received. Mailing of such notice of redemption shall not be a condition precedent to such redemption and failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the 2004 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the 2004 Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if moneys sufficient for the redemption of the 2004 Bonds to be redeemed, together with interest thereon to the redemption date, are held by the Trustee for such 2004 Bonds on the redemption date and the 2004 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. Energy Northwest may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry only system is in effect with respect to the 2004 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the 2004 Bonds of a maturity are to be redeemed, DTC or its successor and Participants and Indirect Participants (as such terms are defined in Appendix I — "BOOK-ENTRY ONLY SYSTEM") will determine the particular ownership interests of 2004 Bonds to be redeemed. Any failure of DTC or its successor or a Participant or Indirect Participant to do so, or to notify a Beneficial Owner of a 2004 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of 2004 Bonds.

Neither Energy Northwest, the Trustee nor the Underwriters can give any assurance that DTC, the Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2004-A Bonds or the Columbia 2004-C Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has preserved the right to purchase any 2004 Bonds on the open market at any time and at any price.

DEFEASANCE

The liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions shall be fully discharged and satisfied as to any related 2004 Bond and such 2004 Bond shall no longer be deemed to be outstanding under the Electric Revenue Bond Resolutions when payment of principal of and premium, if any, on such related 2004 Bond, plus interest on such principal to the date thereof shall have been made or shall have been provided for by irrevocably depositing with the Trustee or a paying agent for such 2004 Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) specified "defeasance obligations" maturing or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will assure the availability of sufficient moneys to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to such 2004 Bonds. See Appendix H-1, "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS — Defeasance (Article XI)" for a discussion of defeasance of the 2004 Bonds.

PURPOSE OF ISSUANCE

REFUNDING PROGRAM

In 2000, Bonneville presented its Debt Optimization Proposal ("Bonneville Proposal") to Energy Northwest. The Bonneville Proposal involves the extension of the final maturity to 2018 of outstanding Columbia Net Billed Bonds coming due prior to 2012 through a series of refunding bond issues. A portion of the Columbia 2004-A Bonds and the Columbia 2004-B (Taxable) Bonds are being issued for such purpose. 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 Bonneville 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.

Energy Northwest, in response to the Bonneville Proposal, developed its 2000 Refunding Plan. The 2000 Refunding Plan also reaffirmed the historical debt service savings goals for any future refinancing of Projects 1 and 3 and Columbia Net Billed Bonds. The Executive Board of Energy Northwest formally adopted the 2000 Refunding Plan in October 2000.

In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan. Such Refunding Plan included a revision which incorporated the increase in the average life of outstanding Projects 1 and 3 Net Billed Bonds through the extension of the maturity of such Bonds as a refinancing program objective for any future refinancing of such Bonds. The Project 1 2004-A Bonds, the Project 1 2004-B (Taxable) Bonds, the Project 3 2004-A Bonds and the Project 3 2004-B (Taxable) Bonds are being issued for such purpose. An additional objective of the refinancing program is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville.

In furtherance of the Refunding Program, in July 2003, Citibank, N.A. extended a line of credit to Energy Northwest for each of the Net Billed Projects pursuant to three separate Credit Agreements. Under the Project 1, Columbia and Project 3 Credit Agreements, Energy Northwest may borrow up to $55,720,000, $129,030,000 and $63,835,000, respectively, from time to time during the period from July 25, 2003 to June 25, 2004. Proceeds of advances made under a Credit Agreement may be applied to refinance a portion of the cost of the related Project by providing a portion of the funds necessary to refund principal and, in some cases, interest on certain Prior Lien Bonds maturing on July 1, 2004 issued to finance such Project. Energy Northwest's obligation to repay advances under a Credit Agreement is evidenced by a note (the "Promissory Note") authorized to be executed and delivered by Energy Northwest pursuant to the related Separate Subordinated Resolution. As of May 1, 2004, Energy Northwest had borrowed $46,433,333.30, $105,585,675.50 and $48,834,316.68 under the Project 1, Columbia and Project 3 Credit Agreements, respectively. Energy Northwest expects to borrow additional amounts prior to the issuance of the 2004 Bonds. Each Promissory Note is secured on a parity with Electric Revenue Bonds issued by Energy Northwest under the related Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Separate Subordinated Resolutions. A portion of the proceeds of the Series 2004-A Bonds is to be applied to pay the Promissory Notes.

In addition, Energy Northwest expects to enter into credit agreements with Citibank, N.A. in July 2004, substantially similar to the Credit Agreements entered into in 2003, for the purpose of extending the maturity of the Net Billed Bonds maturing in 2005.

REFUNDED OBLIGATIONS

The Project 1 2004-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $51,076,666.63 Project 1 Promissory Note) of refunding (i) $55,720,000.00 aggregate principal amount of the Project 1 Prior Lien Bonds and (ii) $11,190,000.00 aggregate principal amount of the Project 1 Electric Revenue Bonds.

The Columbia 2004-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $117,307,837.75 Columbia Promissory Note) of refunding (i) $444,395,000.00 aggregate principal amount of the Columbia Prior Lien Bonds and (ii) $6,030,000.00 aggregate principal amount of the Columbia Electric Revenue Bonds.

The Project 3 2004-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $56,334,658.35 Project 3 Promissory Note) of refunding (i) $63,835,000.00 aggregate principal amount of Project 3 Prior Lien Bonds and (ii) $25,240,000.00 aggregate principal amount of Project 3 Electric Revenue Bonds.

The Project 1 2004-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 1 2004-A Bonds and Project 1 2004-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Project 1 Prior Lien Bonds and Project 1 Electric Revenue Bonds.

The Columbia 2004-B (Taxable) Bonds are being issued for the purpose of paying certain costs relating to the issuance of the Columbia 2004-A Bonds and Columbia 2004-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Columbia Prior Lien Bonds and Columbia Electric Revenue Bonds, and to finance a portion of the cost of certain capital improvements at the Columbia Generating Station. See "PURPOSE OF ISSUANCE — COLUMBIA 2004-C BONDS" for additional information with respect to the capital improvements to be financed from a portion of the proceeds of the Columbia 2004-B (Taxable) Bonds.

The Project 3 2004-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 3 2004-A Bonds and the Project 3 2004-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Project 3 Prior Lien Bonds and Project 3 Electric Revenue Bonds.

A major portion of the proceeds of the Series 2004-A Bonds and the Series 2004-B (Taxable) Bonds and other available amounts will be used to purchase investment securities permitted by the Prior Lien Resolutions and the Electric Revenue Bond Resolutions, respectively (the "Investment Securities"), maturing in such amounts and at such times as shall be sufficient, together with the interest to accrue thereon, to pay the principal or redemption price, if any, of all of the Prior Lien Bonds and Electric Revenue Bonds to be refunded as set forth in the table below and to pay interest on all Prior Lien Bonds and fixed rate Electric Revenue Bonds to be refunded to the date of their retirement. Concurrently with such purchase of Investment Securities, Energy Northwest shall deposit such Investment Securities in separate trust funds established with the Bond Fund Trustee for each of the Series of Prior Lien Bonds and Electric Revenue Bonds to be refunded pursuant to escrow agreements between Energy Northwest and the Bond Fund Trustee for each of such Series of Prior Lien Bonds and Electric Revenue Bonds to be refunded. At the time of such deposit, Energy Northwest shall direct the Bond Fund Trustee for each of the Series of the Prior Lien Bonds and Electric Revenue Bonds to be redeemed, if any, to give notice of redemption of such Prior Lien Bonds and Electric Revenue Bonds.

The accuracy of (1) the arithmetical computations as to the adequacy of the principal of and interest on the Investment Securities, together with other available funds, to pay the principal or redemption price, if any, of the Prior Lien Bonds and Electric Revenue Bonds to be refunded and to pay interest on all Prior Lien Bonds and fixed rate Electric Revenue Bonds to be refunded to the date of their retirement, and (2) the mathematical computations of the yields on the Series 2004-A Bonds and the Series 2004-B (Taxable) Bonds and the adjusted yields on the investments acquired with the proceeds of the Series 2004-A Bonds and the Series 2004-B (Taxable) Bonds will be verified by Bond Logistix LLC.

Information relating to the Prior Lien Bonds and Electric Revenue Bonds to be paid or redeemed with the proceeds of the 2004 Bonds and other funds is set forth as follows:

Prior Lien Bonds:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Payment/ Redemption Date	Redemption Price
1	1992A	$640,000	2004	5.90%	July 1, 2004	N/A
1	1993A	16,435,000	2004	5.50	July 1, 2004	N/A
1	1993B	3,240,000	2004	5.10	July 1, 2004	N/A
1	1993C	1,630,000	2004	4.90	July 1, 2004	N/A
1	1996A	12,975,000	2004	5.50	July 1, 2004	N/A
1	1996B	19,185,000	2004	6.00	July 1, 2004	N/A
1	1996C	415,000	2004	5.00	July 1, 2004	N/A
1	1997B	930,000	2004	5.00	July 1, 2004	N/A
1	1998A	270,000	2004	5.00	July 1, 2004	N/A
Columbia	1990C	18,100,000*	2004	0.00	July 1, 2004	N/A
Columbia	1992A	1,070,000	2004	5.90	July 1, 2004	N/A
Columbia	1993A	14,055,000	2004	5.50	July 1, 2004	N/A
Columbia	1994A	70,170,000	2004	4.80	July 1, 2004	N/A
Columbia	1994A	89,410,000	2008	5.25	July 2, 2004	102%
Columbia	1994A	74,730,000	2009	5.00	July 2, 2004	102%
Columbia	1994A	96,465,000	2010	5.375	July 2, 2004	102%
Columbia	1994A	54,760,000	2011	5.375	July 2, 2004	102%
Columbia	1996A	19,885,000	2004	5.50	July 1, 2004	N/A
Columbia	1997B	5,000,000	2004	5.50	July 1, 2004	N/A
Columbia	1998A	750,000	2004	5.00	July 1, 2004	N/A
3	1989A	4,125,000*	2004	0.00	July 1, 2004	N/A
3	1989B	25,000,000*	2004	0.00	July 1, 2004	N/A
3	1990B	12,000,000*	2004	0.00	July 1, 2004	N/A
3	1993B	9,100,000	2004	5.10	July 1, 2004	N/A
3	1993C	7,240,000	2004	4.90	July 1, 2004	N/A
3	1996A	320,000	2004	5.50	July 1, 2004	N/A
3	1997A	525,000	2004	5.00	July 1, 2004	N/A
3	1998A	5,525,000	2004	5.00	July 1, 2004	N/A

Electric Revenue Bonds:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Payment/ Redemption Date	Redemption Price
1	1993-1A	$5,590,000	2017	Variable	July 1, 2004	100%
1	2001-A	5,600,000	2004	5.50%	July 1, 2004	N/A
Columbia	1997-2A	6,030,000	2012	Variable	July 1, 2004	100%
3	1993-3A	930,000	2018	Variable	July 1, 2004	100%
3	1998-3A	5,680,000	2018	Variable	July 1, 2004	100%
3	2001-A	18,630,000	2004	5.00%	July 1, 2004	N/A

* Matured Value of Compound Interest Bonds.

COLUMBIA 2004-C BONDS

The Columbia 2004-C Bonds are being issued to finance a portion of the costs incurred or planned to be incurred during fiscal years 2004 and 2005 of certain capital improvements at Columbia and to pay costs of issuance relating to the Columbia 2004-C Bonds. The capital improvements at Columbia include security projects, jet pump modification, replacement of process radiation monitors, upgrade the CPU/MUX, independent spent fuel storage cask loading, critical spares, installation of hydrogen water chemistry system, emergency diesel generator power to battery chargers, and replacement of various pieces of equipment.

ESTIMATED SOURCES AND USES OF FUNDS

SOURCES OF FUNDS:

Project 1

Principal of Project 1 2004-A Bonds	$ 62,485,000.00
Principal of Project 1 2004-B (Taxable) Bonds	1,135,000.00
Net Original Issue Premium Project 1 Bonds	4,417,306.60
Moneys Available Under Project 1 Prior Lien Resolution	52,381,779.13
Total	$120,419,085.73

Columbia

Principal of Columbia 2004-A Bonds	$422,350,000.00
Principal of Columbia 2004-B (Taxable) Bonds	12,715,000.00
Principal of Columbia 2004-C Bonds	26,620,000.00
Net Original Issue Premium Columbia Bonds	29,773,430.45
Moneys Available Under Columbia Prior Lien Resolution	126,596,516.31
Total	$618,054,946.76

Project 3

Principal of Project 3 2004-A Bonds	$ 83,835,000.00
Principal of Project 3 2004-B (Taxable) Bonds	1,515,000.00
Net Original Issue Premium Project 3 Bonds	5,232,980.55
Moneys Available Under Project 3 Prior Lien Resolution	56,847,900.00
Total	$147,430,880.55

USES OF FUNDS:

Project 1

Deposit with escrow trustee for refunded Project 1 Prior Lien Bonds	$ 57,240,845.27
Deposit with escrow trustees for refunded Project 1 Electric Revenue Bonds	11,335,029.67
Project 1 Promissory Note Repayment	51,076,666.63
Costs of Issuance including Underwriters' Compensation	766,544.16
Total	$120,419,085.73

Columbia

Deposit with escrow trustee for refunded Columbia Prior Lien Bonds	$461,459,369.32
Deposit with escrow trustee for refunded Columbia Electric Revenue Bonds	6,025,231.75
Columbia Promissory Note Repayment	117,307,837.75
Capital Improvements	28,800,000.00
Costs of Issuance including Underwriters' Compensation	4,462,507.94
Total	$618,054,946.76

Project 3

Deposit with escrow trustee for refunded Project 3 Prior Lien Bonds	$64,353,555.52
Deposit with escrow trustees for refunded Project 3 Electric Revenue Bonds	25,685,423.64
Project 3 Promissory Note Repayment	56,334,658.35
Costs of Issuance including Underwriters' Compensation	1,057,243.04
Total	$147,430,880.55

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2004 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 1 which pledge is subject, so long as any of the Project 1 Prior Lien Bonds remain outstanding ($948,610,000 of which were outstanding as of May 1, 2004), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2004 Bonds are a charge on the receipts, income and revenues of Project 1 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 1 Prior Lien Resolution and payments required to be made under the Project 1 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 1, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 1 2004 Bonds are also secured by a pledge of the proceeds of the sale of Project 1 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 1 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 1 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 1 Electric Revenue Bond Resolution, the Project 1 2004 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest for Project 1 or other obligations of Energy Northwest that are secured pursuant thereto or pursuant to any Project 1 Separate Subordinated Resolution. There were outstanding as of May 1, 2004, $1,032,005,000 principal amount of Project 1 Electric Revenue Bonds.

The Columbia 2004 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Columbia which pledge is subject, so long as any of the Columbia Prior Lien Bonds remain outstanding ($1,351,167,164 of which were outstanding as of May 1, 2004), to the lien and pledge of the Columbia Prior Lien Resolution. The Columbia 2004 Bonds are a charge on the receipts, income and revenues of Columbia subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Columbia Prior Lien Resolution and payments required to be made under the Columbia Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Columbia, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Columbia 2004 Bonds are also secured by a pledge of the proceeds of the sale of Columbia Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Columbia Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Columbia Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Columbia Electric Revenue Bond Resolution, the Columbia 2004 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest for Columbia or other obligations of Energy Northwest that are secured pursuant thereto or pursuant to any Columbia Separate Subordinated Resolution. There were outstanding as of May 1, 2004, $818,410,000 principal amount of Columbia Electric Revenue Bonds.

The Project 3 2004 Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 3 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 3 which pledge is subject, so long as any of the Project 3 Prior Lien Bonds remain outstanding ($907,415,973 of which were outstanding as of May 1, 2004), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2004 Bonds are a charge on the receipts, income and revenues of Project 3 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 3 Prior Lien Resolution and payments required to be made under the Project 3 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 3, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 3 2004 Bonds are also secured by a pledge of the proceeds of the sale of Project 3 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 3 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 3 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 3 Electric Revenue Bond Resolution, the Project 3 2004 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest or other obligations of Energy Northwest that are secured pursuant thereto or pursuant to any Project 3 Separate Subordinated Resolution. There were outstanding as of May 1, 2004, $1,004,980,000 principal amount of Project 3 Electric Revenue Bonds.

Energy Northwest has covenanted with the owners of the Electric Revenue Bonds that it will not issue any more Prior Lien Bonds or any other bonds, warrants or other obligations which will rank on a parity with the pledge of and lien on the revenues created by the related Prior Lien Resolution.

Amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 1 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 1 2004 Bonds, subject to the payments required in connection with the Project 1 Prior Lien Bonds as described in the following sentence. So long as any of the Project 1 Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Project 1 Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Project 1 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Project 1 Electric Revenue Bonds, including the Project 1 2004 Bonds. See “NET BILLING AND RELATED AGREEMENTS” below.

Amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements entered into among Energy Northwest, Bonneville and the Columbia Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Columbia 2004 Bonds, subject to the payments required in connection with the Columbia Prior Lien Bonds as described in the following sentence. So long as any of the Columbia Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Columbia Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Columbia Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Columbia Electric Revenue Bonds, including the Columbia 2004 Bonds. See “NET BILLING AND RELATED AGREEMENTS” below.

Amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 3 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 3 2004 Bonds, subject to the payments required in connection with the Project 3 Prior Lien Bonds as described in the following sentence. So long as any of the Project 3 Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Project 3 Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Project 3 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Project 3 Electric Revenue Bonds, including the Project 3 2004 Bonds. See “NET BILLING AND RELATED AGREEMENTS” below.

Bonneville may make only such expenditures from the Bonneville Fund as shall have been included in budgets submitted annually to Congress. Bonneville includes in its annual budget submittal to Congress an amount sufficient to cover its obligations under the Net Billing Agreements, including the payment of debt service on the Net Billed Bonds. Bonneville may make such expenditures without further appropriation and without fiscal year limitation, but subject to such specific directives or limitations on use of the Bonneville Fund as may be included by Congress in appropriation acts. 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 complete discussion of the Bonneville Fund, see Appendix A — “THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund” in this Official Statement.

The Project 1 2004 Bonds, the Columbia 2004 Bonds and the Project 3 2004 Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2004 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2004 Bonds and the Project 3 2004 Bonds. The owners of the Columbia 2004 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2004 Bonds and the Project 3 2004 Bonds. The owners of the Project 3 2004 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2004 Bonds and the Columbia 2004 Bonds. No Bondholder has a claim on the assets of any Project.

The 2004 Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power.

See Appendix H-1 — “SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS.”

EVENTS OF DEFAULT AND REMEDIES

For a description of the events of default and remedies applicable to the Electric Revenue Bonds, including the 2004 Bonds, see Appendix H-1 — “SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS – Events of Default.”

Under each Prior Lien Resolution, the happening of one or more of the following events constitutes an Event of Default: (i) default in the performance of any obligation with respect to payments into the respective Revenue Fund; (ii) default in the payment of the principal of and premium, if any, or default for 30 days in the payment of interest on any of the respective Prior Lien Bonds or any sinking fund installment on any Project 1, Columbia or Project 3 Prior Lien Bonds; (iii) default for 90 days in the observance and performance of any other of the covenants, conditions and agreements of Energy Northwest in the respective Prior Lien Resolution; (iv) the sale or conveyance of any properties of the respective Net Billed Project except as permitted by the respective Prior Lien Resolution or the voluntary forfeiture of any license, franchise, permit or other privilege necessary or desirable in the operation of such Project; and (v) certain acts related to the insolvency or bankruptcy of Energy Northwest. Both the applicable Prior Lien Bond Fund Trustee and the holders of not less than 20% in aggregate principal amount of the respective Prior Lien Bonds then outstanding under the respective Prior Lien Resolution have the right to accelerate the maturity of such Prior Lien Bonds after an Event of Default occurs under such Resolution. See Appendix H-2 — “SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS — Events of Default; Remedies.”

Under each Prior Lien Resolution, the covenants referred to in clause (iii) of the preceding paragraph include the following, among others: (a) completing construction of the respective Net Billed Project at the earliest practicable time, operating such Project and the business in connection therewith in an efficient manner and at reasonable cost, maintaining such Project in good condition and making all necessary and proper repairs, renewals and replacements and (b) maintaining and collecting rates and charges for capability, power and energy and other services, facilities and commodities sold, furnished or supplied through such Project which will be adequate, whether or not the generation or transmission of power by such Project is suspended, interrupted or reduced for any reason whatsoever, to provide revenues sufficient, among other things, to pay the expenses of operating and maintaining such Project and the debt service on the related Prior Lien Bonds. See Appendix H-2 — "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS — Certain Covenants."

If the maturity of Prior Lien Bonds or Electric Revenue Bonds, including the 2004 Bonds, were accelerated by the applicable Bond Fund Trustee or Trustee or the holders of the requisite principal amount of such Bonds after an Event of Default under the respective Prior Lien Resolution or Electric Revenue Bond Resolution, no assurance can be given that the principal amount of the accelerated Prior Lien Bonds or Electric Revenue Bonds would be payable currently as a cost under the terms of the Net Billing Agreements related to such Net Billed Project. See "NET BILLING AND RELATED AGREEMENTS — Payment Procedures" and "SECURITY FOR THE NET BILLED BONDS — LIMITATIONS ON REMEDIES" for a discussion of the limitations of certain remedies. The Promissory Notes described under "PURPOSE OF ISSUANCE" are also subject to acceleration under the applicable Credit Agreement.

If Bonneville and the Participants were obligated only to provide funds to meet the scheduled amounts due on the respective Prior Lien Bonds and not the amounts due upon acceleration, moneys intended to be applied to the payment of the respective Electric Revenue Bonds would be applied by the applicable Prior Lien Bond Fund Trustee to payment of such Prior Lien Bonds, and the Electric Revenue Bonds would not be paid until such Prior Lien Bonds ceased to be outstanding or the Event of Default giving rise to such acceleration were cured.

See Appendix H-2 — "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS" for further information.

Payments and the provision of credits by Bonneville and payments by Participants under the Net Billing Agreements relating to Project 1, the Columbia Generating Station or Project 3, respectively, that are required to be made to Energy Northwest to pay the principal of and interest on the outstanding Net Billed Bonds issued for the related Net Billed Project are required to be made notwithstanding the occurrence of an Event of Default. In the case of each Net Billed Project, if an Event of Default occurs under the related Prior Lien Resolution, whether or not such Event of Default gives rise to an acceleration of the maturity of the Prior Lien Bonds outstanding under such Resolution, Energy Northwest is required under such Resolution to pay all revenues of such Project thereafter received by it upon demand to the applicable Prior Lien Bond Fund Trustee until all such Prior Lien Bonds have been paid in full or such Event of Default has been cured, whichever occurs first. In such event, moneys intended to be applied to the payment of related Electric Revenue Bonds would be paid instead to the applicable Prior Lien Bond Fund Trustee and such Electric Revenue Bonds would not be paid until such Prior Lien Bonds have been paid in full or such Event of Default has been cured, whichever occurs first.

LIMITATIONS ON REMEDIES

Upon the occurrence of an Event of Default under the Electric Revenue Bond Resolutions and Prior Lien Resolutions, payment of the principal of and interest on the 2004 Bonds may be accelerated. Any action to compel payment, for money damages or to accelerate payment would be subject to the limitations on legal claims and remedies against public bodies under Washington law. The right to accelerate payments by a Washington municipality has not been tested by any Washington court. Any remedies available to Bondholders are in many respects dependent upon judicial actions which are in turn often subject to discretion and delay and can be expensive and time-consuming to obtain. If Energy Northwest fails to comply with its covenants under the Electric Revenue Bond Resolutions or to pay principal of or interest on the 2004 Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the 2004 Bonds. See "SECURITY FOR THE NET BILLED BONDS — EVENTS OF DEFAULT AND REMEDIES" for a discussion of possible limits of amounts payable under the Net Billing Agreements in the event of acceleration of the Net Billed Bonds.

In addition to the limitations on remedies in the Electric Revenue Bond Resolutions, the rights and obligations under the 2004 Bonds may be limited by and are subject to bankruptcy, insolvency, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases. The opinions to be delivered by Preston Gates & Ellis LLP, as Bond Counsel, concurrently with the issuance of the 2004 Bonds, will be subject to limitations regarding such creditors' rights. See Appendix D-1 — "PROPOSED FORMS OF OPINIONS OF BOND COUNSEL" and Appendix D-2 — "PROPOSED FORMS OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL", respectively.

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the 2004 Bonds. In the Electric Revenue Bond Resolutions, Energy Northwest has reserved the right to create a reserve account to secure a separate series of Electric Revenue Bonds.

ADDITIONAL INDEBTEDNESS

The Electric Revenue Bonds are subordinate to the Prior Lien Bonds. In each Electric Revenue Bond Resolution, Energy Northwest has reserved the right to issue, upon satisfaction of certain conditions set forth therein, additional bonds or notes under the Electric Revenue Bond Resolutions and under one or more separate resolutions ("Separate Subordinated Resolutions") of the Executive Board creating a pledge of and lien on the receipts, income and revenues derived from the related Project of equal rank with the pledge and lien created by such Electric Revenue Bond Resolution in favor of the Electric Revenue Bonds. Each Promissory Note which is to be paid from the proceeds of the Series 2004-A Bonds and the Series 2004-B (Taxable) Bonds and similar notes to be issued pursuant to credit agreements to be executed in 2004 have been or will be, as the case may be, issued pursuant to Separate Subordinated Resolutions. There are no restrictions on or conditions to issuing debt on a parity with the Electric Revenue Bonds under the Electric Revenue Bond Resolutions, including the 2004 Bonds, pursuant to Separate Subordinated Resolutions, other than the Net Billing Agreements and other Project agreements being in effect and no event of default is existing under the applicable Electric Revenue Bond Resolution.

Conditions to the issuance of additional bonds pursuant to the Electric Revenue Bond Resolutions are described in Appendix H-1 — "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

Each of the Electric Revenue Bond Resolutions permits the use of certain credit facilities of the type referred to in such Electric Revenue Bond Resolution to secure the payment of the related Electric Revenue Bonds and the incurrence by Energy Northwest of reimbursement obligations of the type referred to in such Electric Revenue Bond Resolution to reimburse the issuer of a credit facility. Each of the Electric Revenue Bond Resolutions also permits the use of interest rate exchange agreements or similar agreements. Such reimbursement obligations or obligations of Energy Northwest under such interest rate exchange agreements, including any termination payments owed by Energy Northwest, may be secured on a parity with the lien created by the Electric Revenue Bond Resolutions in favor of the related Electric Revenue Bonds. See Appendix H-1 — "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

For information regarding the amount of bonds and other obligations of Energy Northwest outstanding under the Electric Revenue Bond Resolutions and Separate Subordinated Resolutions, see "ENERGY NORTHWEST – ENERGY NORTHWEST INDEBTEDNESS."

NET BILLING AND RELATED AGREEMENTS

General

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 its ownership share 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"). Under the Net Billing Agreements, each Participant assigned its share of the Net Billed Project capability to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project. See Appendix F — "ENERGY NORTHWEST PARTICIPANT UTILITY SHARE FISCAL YEAR 2004 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2004 Budgets.

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 referred to below under "NET BILLING AND RELATED AGREEMENTS — Payment Procedures." 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 described below (subject to the limitations described herein under Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund"). 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.

The Net Billing Agreements provide for cash payments and the provision of credits by Bonneville and payments by Participants 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.

The Net Billing Agreements require each Participant to pay Energy Northwest the amount set forth in its Billing Statement or accounting statement. Each Participant is required to make payments to Energy Northwest only from revenues derived by the Participant from the ownership and operation of its electric utility properties and from payments made by Bonneville under the Net Billing Agreements. Each Participant has covenanted that it will establish, maintain and collect rates or charges for power and energy and other services furnished through its electric utility properties which shall be adequate to provide revenues sufficient to make required payments to Energy Northwest under the Net Billing Agreements and to pay all other charges and obligations payable from or constituting a charge and lien upon such revenues.

The authority of all of the Participants to enter into the Net Billing Agreements was affirmed in 1985 by the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System, et. al* ("the Springfield Case"). The United States Supreme Court denied a petition for a writ of certiorari. In upholding the Net Billing Agreements, the court in the Springfield Case found that the Net Billing Agreements are contracts for the purchase of electricity because the Net Billing Agreements place the dry hole risk on Bonneville and not on the Participants and because the Participants will receive either electricity or a cash refund equal to their payments to Energy Northwest. For a discussion of Bond Counsel's opinion with respect to the enforceability of the Net Billing Agreements see "LEGAL MATTERS." For a summary of certain provisions of the Net Billing Agreements, see Appendix G — "SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

Pending the receipt of the ruling in the Springfield Case, Energy Northwest and Bonneville entered into certain Assignment Agreements for each of Project 1, Columbia and Project 3 (the "Assignment Agreements"). For additional information with respect to the Assignment Agreements, see "NET BILLING AND RELATED AGREEMENTS – Assignment Agreements" and Appendix G — "SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS".

By letter dated August 1, 1989 (the "1989 Letter Agreement"), Bonneville agreed with Energy Northwest that, in the event any Participant shall be unable for any reason, or shall fail or 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 Bonneville, Bonneville 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.

All payments required to be made by Bonneville under the Net Billing Agreements, the Assignment Agreements and the 1989 Letter Agreement are to be made from the Bonneville Fund or other funds legally available therefor. See "THE BONNEVILLE FUND" below.

Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.

Payment Procedures

The Columbia Net Billing Agreements provide for the adoption by Energy Northwest of an Annual Budget, which, as amended from time to time, shall make provision for all Columbia costs, including but not limited to, the amounts which Energy Northwest is required to pay in each contract year (July 1 to June 30) into the various funds provided for in the Columbia Prior Lien Resolution and the Columbia Electric Revenue Bond Resolution for debt service and all other purposes. The Annual Budget also includes the source of funds proposed to be used. The Annual Budget is submitted to Bonneville and to the Participants' Review Board established under the Columbia Net Billing Agreements and becomes effective 30 days after submitted unless it is disapproved by Bonneville or unless a recommendation or modification proposed by the Participants' Review Board is not accepted by Energy Northwest. In the event of a dispute, the matter is referred to a Project Consultant as described in Appendix G — "SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS — The Project Agreements." Energy Northwest prepares a Billing Statement for that contract year for each Columbia Participant. The Billing Statement shows such Participant's share of the Annual Budget for Columbia less amounts payable from sources other than the Columbia Net Billing Agreements. The Annual Budget and Billing Statements may be amended during a contract year, if necessary. As described below, each Participant makes monthly payments to Energy Northwest in satisfaction of the amounts due under its Billing Statement.

In the month preceding the beginning of each contract year and in each month thereafter, Bonneville renders a bill to each Participant for power and other services under the Participant's power sales and other contracts with Bonneville. In the first month of the contract year, that bill shows an offsetting credit equal to the full amount of such bill to the extent of the Participant's share of the costs of Columbia. Within 30 days of receiving the monthly bill from Bonneville reflecting such credit, the Participant must pay Energy Northwest an amount equal to the credit for Columbia received from Bonneville. In each month thereafter during the contract year, such crediting by Bonneville and such payments to Energy Northwest by such Participant, continue until the credits received by such Participant equal the total amount shown on such Participant's Billing Statement. The effect of this payment procedure is that amounts due Bonneville from the Participants (up to the Participants' obligations to Energy Northwest as shown on their Billing Statements), are required to be paid by the Participants to Energy Northwest rather than to Bonneville.

Project 1 and Project 3 have been terminated and in accordance with the Net Billing Agreements for such Projects, the related Net Billing Agreements terminated except for those provisions that provide for the billing and payment of the costs of such Net Billed Project including all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution or Prior Lien Resolution to pay each year into the various funds for debt service and all other purposes, and the crediting of the proceeds of the disposition of the assets of such terminated Net Billed Project in reduction of such costs. The costs for each Net Billed Project after termination include all of Energy Northwest's accrued costs and liabilities resulting from Energy Northwest's ownership, construction, operation (including cost of fuel) and maintenance of and renewals and replacements to the terminated Project and all other Energy Northwest costs resulting from its ownership of such Project and the salvage, discontinuance, decommissioning and disposition or sale thereof and all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution or Prior Lien Resolution to pay in each year into the various funds for debt service and all other purposes. The Columbia Net Billing Agreements have the same termination provision.

Since Projects 1 and 3 have been terminated, Energy Northwest is required under each of the Projects 1 and 3 Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Project 1 Participant or Project 3 Participant of all costs associated with such termination. The monthly accounting statements are required to credit against such costs all amounts received by Energy Northwest from the disposition of assets of Project 1 and from the disposition of assets of Project 3. The Project 1 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 1 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 1, whichever is later. The Project 3 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 3 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 3, whichever is later. If the monthly accounting statements show that such costs exceed such credits, each Project 1 Participant or Project 3 Participant, as the case may be, is required to pay its portion of such excess costs to Energy Northwest. The payments are to be made at times and in amounts sufficient to discharge on a current basis the Project 1 Participant's share or Project 3 Participant's share, as the case may be, of the amount which Energy Northwest is required to pay into the various funds provided in the related Electric Revenue Bond Resolution or Prior Lien Resolution for debt service and all other purposes.

In the event of a termination of the Columbia Generating Station, Energy Northwest is required under the Columbia Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Columbia Participant of all costs associated with such termination in the manner discussed above for Projects 1 and 3.

Post Termination Agreements

Bonneville and Energy Northwest have entered into Post Termination Agreements with respect to Projects 1 and 3, each dated June 14, 1994, respectively (the "Post Termination Agreements") which, among other things, facilitate the administration, budgeting and billing procedures with respect to such Projects. Nothing in the Post Termination Agreements impairs or prevents Energy Northwest from including in the monthly accounting statements with respect to each such Project all costs and obligations of Energy Northwest as discussed above.

Assignment of Participant Shares

If Bonneville determines that a Participant's payment obligations to Bonneville under its power sales and other contracts will not equal or exceed the Participant's payment obligations during a contract year under its Net Billing Agreement and, in the opinion of Bonneville and the Participant, such deficiency is expected to continue for a significant period, Bonneville is required under the related Net Billing Agreement to use its best efforts to assign such Participant's share of capability in the Net Billed Project (and the associated benefits and obligations) to other Participants in the Net Billed Project or to other Bonneville customers to the extent necessary to eliminate such Participant's net billing deficiency. The Net Billed Project capability so assigned would then be included by Bonneville under net billing arrangements with such other Participant or customer.

If Bonneville were unable to arrange for such assignments, the Participant would be required to make such assignment to other Participants pro rata. The other Participants would be obligated to accept such assignments to the extent required to eliminate such deficiency. Such mandatory assignments to any Participant may not exceed 25% of that Participant's original share of the Net Billed Project capability without the consent of that Participant. In addition, no such mandatory assignment may be made if it would cause the estimate of that Participant's obligation to Energy Northwest to exceed the estimate of the credits available to it from Bonneville, as estimated by Bonneville. Bonneville has made voluntary payments directly to Energy Northwest on behalf of Participants prior to reassigning their shares to eliminate net billing deficiencies. See "NET BILLING AND RELATED AGREEMENTS — Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants."

The Net Billing Agreements provide that if reassignments cannot be made in amounts sufficient to bring into balance the respective dollar obligations of Bonneville and a Participant and an accumulated balance in favor of such Participant from a previous contract year is expected by Bonneville to be carried for an additional contract year, Bonneville is obligated to pay the balance. Any subsequent monthly net balances that exceed the amount of Bonneville's bill for that month will be paid to such Participant by Bonneville as cash deficiency payments, subject to the limitations described herein under Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund." The Participants are obligated to pay to Energy Northwest the amounts received from Bonneville within 30 days.

Voluntary Payments By Bonneville To Energy Northwest on Behalf of Participants

In 1979 and 1980, Bonneville and Energy Northwest entered into agreements with a large portion of the Participants (representing between roughly 70%-80% of the capability of each Project, depending on the Project) relating to payments to Energy Northwest under the Net Billing Agreements. These agreements ("Voluntary Payment Agreements") provide that Bonneville, prior to making a reassignment of a Participant's share, may (but is not required to) pay directly to Energy Northwest, for the account of the Participant, the amount by which the Participant's obligation to Energy Northwest exceeds the billing credits allowed or estimated to be allowed to the Participant during the contract year. Under the Voluntary Payment Agreements, the related Participants agreed that they would not seek payment from Bonneville for any amounts so paid to Energy Northwest. In the case of Participants that have not signed such Agreements, Bonneville has nonetheless made a number of similar voluntary payments to Energy Northwest on their behalves. When Bonneville does so it notifies the related Participants by letter that it has made such voluntary payments to Energy Northwest. See Appendix A — "BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Order in Which Bonneville's Costs Are Met" for more information. Because of these payments, no reassignments of Participants' shares or deficiency payments by Bonneville to Participants have been necessary. These payments have also assisted in managing the cash flow requirements of Energy Northwest.

Assignment Agreements

Pursuant to the Assignment Agreements, Energy Northwest assigned to Bonneville any rights to the capability of any of the Net Billed Projects that Energy Northwest may obtain as a result of a reversion of a Participant's share of such capability to Energy Northwest or otherwise. In the event that it is judicially determined that any Participant is not obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agreed to pay directly to Energy Northwest the amounts that would have been payable by the Participant under the Net Billing Agreements for such Project capability. For a summary of certain provisions of the Assignment Agreements, see Appendix G — "SUMMARY OF CERTAIN PROVISIONS OF RELATED AGREEMENTS."

Other Net Billing Obligations

In addition to the net billing obligations in connection with the Net Billed Projects, Bonneville has net billing obligations to certain Participants in connection with that portion of the project capability associated with the share of the Trojan Nuclear Project owned by the City of Eugene Water and Electric Board ("EWEB"). The credits and payments received by each Participant from Bonneville in each month under all of that Participant's agreements providing for net billing are required by the Net Billing Agreements to be allocated pro rata among all of the Participants' net billing obligations.

Bonneville is authorized to enter into additional contracts providing for net billing or similar credits. The Net Billing Agreements provide that Bonneville and each Participant shall not enter into any agreement providing for net billing if Bonneville estimates that, as a result of such agreement, the aggregate of its billings to such Participant will be less than 115% of Bonneville's net billing obligations to such Participant under all agreements between Bonneville and such Participant providing for net billing. Bonneville has no present plans to enter into new agreements requiring net billing with Participants.

THE BONNEVILLE FUND

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

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

Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Net Billed Projects, to the extent covered by net billing credits, can be met without regard to amounts in the Bonneville Fund.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System (as defined in Appendix A — "THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (i) the repayment of the 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 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 2003 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 cash deficiency payments relating to Net Billed 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 other cash payments of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

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

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) Net Billed Project costs and Trojan 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 net billing cash payments, but excluding payments to the United States Treasury and (3) payments to the United States Treasury.

For further information, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Order in Which Bonneville's Costs Are Met." For a discussion of certain proposed and current direct payments by Bonneville for Federal System operations and maintenance, which payments would reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense" and "Developments Relating to Bonneville Power Marketing Approach and Bonneville's Financial Condition – Fiscal Year 2004 Developments."

Bonneville's obligation under the Project 1 Net Billing Agreements is to pay an amount equal to the costs of Project 1 less any other funds which shall be specified in the Annual Budget as payable from sources other than the payments to be made under the Net Billing Agreements. Similar language is found in the Net Billing Agreements for Columbia and Project 3. In the opinion of Bonneville's General Counsel, this provision would permit Bonneville to make payments on account of debt service on all Net Billed Bonds for a Net Billed Project directly to the applicable Bond Fund Trustee or Trustee. Such payment would be made only pursuant to an agreement with the applicable Bond Fund Trustee or Trustee requiring Bonneville to make such payment directly to the applicable Bond Fund Trustee or Trustee on or before the date such amounts would be required to be paid by Energy Northwest to the applicable Bond Fund Trustee or Trustee under the applicable Net Billed Resolution. Bonneville has no present intention of undertaking such actions. The effect of such an agreement would be to reduce the amount of costs included in the Annual Budget for the Net Billed Project to be paid under the Net Billing Agreements by the amount of the debt service payable directly by Bonneville to the applicable Bond Fund Trustee or Trustee.

For further information see Appendix A — "THE BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS."

BOND INSURANCE

MBIA Financial Guaranty Insurance Policy

Concurrently with the issuance of the 2004 Bonds, MBIA Insurance Corporation ("MBIA") will issue its Financial Guaranty Policies (the "MBIA's policy") for the Project 1 2004-A Bonds in the aggregate principal amount of $62,485,000 due July 1, 2013, the Columbia 2004-A Bonds in the aggregate principal amount of $20,375,000 due July 1, 2017 and in the aggregate principal amount of $88,885,000 due July 1, 2018, the Project 3 2004-A Bonds in the aggregate principal amount of $26,490,000 due July 1, 2014, in the aggregate principal amount of $26,535,000 due July 1, 2015 and in the aggregate principal amount of $30,810,000 due July 1, 2016, the Columbia 2004-C Bonds in the aggregate principal amount of $2,075,000 due July 1, 2011, in the aggregate principal amount of $2,185,000 due July 1, 2012, in the aggregate principal amount of $1,595,000 due July 1, 2013, in the aggregate principal amount of $2,550,000 due July 1, 2015, in the aggregate principal amount of $2,685,000 due July 1, 2016, in the aggregate principal amount of $2,825,000 due July 1, 2017, and in the aggregate principal amount of $2,970,000 due July 1, 2018. The 2004 Bonds so insured are herein referred to as the "MBIA Insured Bonds."

The following information has been furnished by MBIA Insurance Corporation ("MBIA") for use in this Official Statement. Reference is made to Appendix K-1 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 Issuer to the Paying Agent 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 Paying Agent 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 Paying Agent or any owner of a MBIA Insured Bond 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 Paying Agent payment of the insured amounts due on such MBIA Insured Bonds, less any amount held by the Paying Agent for the payment of such insured amounts and legally available therefor.

MBIA

MBIA Insurance Corporation ("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 the heading "SECURITY FOR THE NET BILLED BONDS — BOND INSURANCE". Additionally, MBIA makes no representation regarding the 2004 Bonds or the advisability of investing in the 2004 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, 2003; and

(2) The Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004.

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 2004 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, 2003, and (2) the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004) 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, 2003, MBIA had admitted assets of $9.9 billion (unaudited), total liabilities of $6.2 billion (unaudited), and total capital and surplus of $3.7 billion (unaudited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities. As of March 31, 2004, MBIA had admitted assets of $10.3 billion (unaudited), total liabilities of $6.5 billion (unaudited), and total capital and surplus of $3.8 billion (unaudited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities.

Financial Strength Ratings of MBIA

Moody's Investors Service, Inc. 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 2004 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 2004 Bonds. MBIA does not guaranty the market price of the 2004 Bonds nor does it guaranty that the ratings on the 2004 Bonds will not be revised or withdrawn.

Ambac Financial Guaranty Insurance Policy

Concurrently with the issuance of the of the 2004 Bonds, Ambac Assurance Corporation ("Ambac") will issue its Financial Guaranty Insurance Policies for the Columbia 2004-A Bonds in the aggregate principal amount of $69,225,000 due July 1, 2009 and in the aggregate principal amount of $38,735,000 due July 1, 2011. The 2004 Bonds so insured are herein referred to as the "Ambac Insured Bonds."

The following information has been furnished by Ambac for use in this Official Statement. Reference is made to Appendix K-2 for a specimen of Ambac's policy.

Payment Pursuant to Financial Guaranty Insurance Policy

Ambac Assurance has made a commitment to issue a financial guaranty insurance policy (the "Financial Guaranty Insurance Policy") relating to the Ambac Insured Bonds effective as of the date of issuance of the Ambac Insured Bonds. Under the terms of the Financial Guaranty Insurance Policy, Ambac Assurance will pay to The Bank of New York, New York, New York or any successor thereto (the "Insurance Trustee") that portion of the principal of and interest on the Ambac Insured Bonds which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor (as such terms are defined in the Financial Guaranty Insurance Policy). Ambac Assurance will make such payments to the Insurance Trustee on the later of the date on which such principal and interest becomes Due for Payment or within one business day following the date on which Ambac Assurance shall have received notice of Nonpayment from the Trustee. The insurance will extend for the term of the Obligations and, once issued, cannot be canceled by Ambac Assurance.

The Financial Guaranty Insurance Policy will insure payment only on stated maturity dates and on mandatory sinking fund installment dates, in the case of principal, and on stated dates for payment, in the case of interest. If the Ambac Insured Bonds become subject to mandatory redemption and insufficient funds are available for redemption of all outstanding Ambac Insured Bonds, Ambac Assurance will remain obligated to pay principal of and interest on outstanding Ambac Insured Bonds on the originally scheduled interest and principal payment dates including mandatory sinking fund redemption dates. In the event of any acceleration of the principal of the Ambac Insured Bonds, the insured payments will be made at such times and in such amounts as would have been made had there not been an acceleration.

In the event the Trustee has notice that any payment of principal of or interest on an Ambac Insured Bond which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from its registered owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such registered owner will be entitled to payment from Ambac Assurance to the extent of such recovery if sufficient funds are not otherwise available.

The Financial Guaranty Insurance Policy does not insure any risk other than Nonpayment, as defined in the Policy. Specifically, the Financial Guaranty Insurance Policy does not cover:

1. payment on acceleration, as a result of a call for redemption (other than mandatory sinking fund redemption) or as a result of any other advancement of maturity.

2. payment of any redemption, prepayment or acceleration premium.

3. nonpayment of principal or interest caused by the insolvency or negligence of any Trustee, Paying Agent or Bond Registrar, if any.

If it becomes necessary to call upon the Financial Guaranty Insurance Policy, payment of principal requires surrender of Ambac Insured Bonds to the Insurance Trustee together with an appropriate instrument of assignment so as to permit ownership of such Ambac Insured Bonds to be registered in the name of Ambac Assurance to the extent of the payment under the Financial Guaranty Insurance Policy. Payment of interest pursuant to the Financial Guaranty Insurance Policy requires proof of Holder entitlement to interest payments and an appropriate assignment of the Holder's right to payment to Ambac Assurance.

Upon payment of the insurance benefits, Ambac Assurance will become the owner of the Ambac Insured Bond, appurtenant coupon, if any, or right to payment of principal or interest on such Ambac Insured Bond and will be fully subrogated to the surrendering Holder's rights to payment.

Ambac Assurance Corporation

Ambac Assurance Corporation ("Ambac Assurance") is a Wisconsin-domiciled stock insurance corporation regulated by the Office of the Commissioner of Insurance of the State of Wisconsin and licensed to do business in 50 states, the District of Columbia, the Territory of Guam, the Commonwealth of Puerto Rico and the U.S. Virgin Islands, with admitted assets of approximately $7,670,000,000 (unaudited) and statutory capital of $4,683,000,000 (unaudited) as of March 31, 2004. Statutory capital consists of Ambac Assurance's policyholders' surplus and statutory contingency reserve. Standard & Poor's Credit Markets Services, a Division of The McGraw-Hill Companies, Moody's Investors Service and Fitch Ratings have each assigned a triple-A financial strength rating to Ambac Assurance.

Ambac Assurance has obtained a ruling from the Internal Revenue Service to the effect that the insuring of an obligation by Ambac Assurance will not affect the treatment for federal income tax purposes of interest on such obligation and that insurance proceeds representing maturing interest paid by Ambac Assurance under policy provisions substantially identical to those contained in its Financial Guaranty insurance policy shall be treated for federal income tax purposes in the same manner as if such payments were made by the Obligor of the Ambac Insured Bonds.

Ambac Assurance makes no representation regarding the 2004 Bonds or the advisability of investing in the 2004 Bonds and makes no representation regarding, nor has it participated in the preparation of, the Official Statement other than the information supplied by Ambac Assurance and presented under the heading "SECURITY FOR THE NET BILLED BONDS — BOND INSURANCE — Ambac Financial Guaranty Insurance Policy.

Available Information

The parent company of Ambac Assurance, Ambac Financial Group, Inc. (the "Company"), is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and in accordance therewith files reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC"). These reports, proxy statements and other information can be read and copied at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. The SEC maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding companies that file electronically with the SEC, including the Company. These reports, proxy statements and other information can also be read at the offices of the New York Stock Exchange, Inc. (the "NYSE"), 20 Broad Street, New York, New York 10005.

Copies of Ambac Assurance's financial statements prepared in accordance with statutory accounting standards are available from Ambac Assurance. The address of Ambac Assurance's administrative offices and its telephone number are One State Street Plaza, 19th Floor, New York, New York, 10004 and (212) 668-0340.

Incorporation of Certain Documents by Reference

The following documents filed by the Company with the SEC (File No. 1-10777) are incorporated by reference in this Official Statement:

1. The Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2003 and filed on March 15, 2004;

2. The Company's Current Report on Form 8-K dated April 21, 2004 and filed on April 22, 2004; and

3. The Company's Quarterly Report on Form 10-Q for the fiscal quarterly period ended March 31, 2004 and filed on May 10, 2004.

All documents subsequently filed by the Company pursuant to the requirements of the Exchange Act after the date of this Official Statement will be available for inspection in the same manner as described above in "Available Information".

Financial Guaranty Municipal Bond New Issue Insurance Policy

Financial Guaranty Insurance Company ("Financial Guaranty") has supplied the following information for inclusion in this Official Statement. No representation is made by Energy Northwest or the Underwriters as to the accuracy or completeness of this information. Reference is made to Appendix K-3 for a specimen of Financial Guaranty's policy.

Payments Under the Policy

Concurrently with the issuance of the FGIC Insured Bonds, Financial Guaranty will issue its Municipal Bond New Issue Insurance Policy (the "FGIC Policy") for the Columbia 2004-A Bonds in the aggregate principal amount of $90,860,000 due July 1, 2010 (the "FGIC Insured Bonds"). The FGIC Policy unconditionally guarantees the payment of that portion of the principal or accreted value (if applicable) of and interest on the FGIC Insured Bonds which has become due for payment, but shall be unpaid by reason of nonpayment by the issuer of the FGIC Insured Bonds (the "Issuer"). Financial Guaranty will make such payments to U.S. Bank Trust National Association, or its successor as its agent (the "Fiscal Agent"), on the later of the date on which such principal, accreted value or interest (as applicable) is due or on the business day next following the day on which Financial Guaranty shall have received notice (in accordance with the terms of the FGIC Policy) from an owner of Bonds or the trustee or paying agent (if any) of the nonpayment of such amount by the Issuer. The Fiscal Agent will disburse such amount due on any Bond to its owner upon receipt by the Fiscal Agent of evidence satisfactory to the Fiscal Agent of the owner's right to receive payment of the principal, accreted value or interest (as applicable) due for payment and evidence, including any appropriate instruments of assignment, that all of such owner's rights to payment of such principal, accreted value or interest (as applicable) shall be vested in Financial Guaranty. The term "nonpayment" in respect of a Bond includes any payment of principal, accreted value or interest (as applicable) made to an owner of a Bond which has been recovered from such owner pursuant to the United States Bankruptcy Code by a trustee in bankruptcy in accordance with a final, nonappealable order of a court having competent jurisdiction.

Once issued, the FGIC Policy is non-cancellable by Financial Guaranty. The FGIC Policy covers failure to pay principal of the FGIC Insured Bonds on their stated maturity dates and their mandatory sinking fund redemption dates, and not on any other date on which the FGIC Insured Bonds may have been otherwise called for redemption, accelerated or advanced in maturity. The FGIC Policy also covers the failure to pay interest on the stated date for its payment. If the FGIC Insured Bonds are accelerated or become subject to mandatory redemption, Financial Guaranty will be obligated to pay principal (or accreted value, if applicable) and interest on the originally scheduled principal (including mandatory sinking fund redemption) and interest payment dates. Upon such payment, Financial Guaranty will become the owner of the FGIC Insured Bond, appurtenant coupon or right to payment of principal or interest on such Bond and will be fully subrogated to all of the Bondholder's rights thereunder.

The FGIC Policy does not insure any risk other than Nonpayment by the Issuer, as defined in the FGIC Policy. Specifically, the FGIC Policy does not cover: (i) payment on acceleration, as a result of a call for redemption (other than mandatory sinking fund redemption) or as a result of any other advancement of maturity; (ii) payment of any redemption, prepayment or acceleration premium; or (iii) nonpayment of principal (or accreted value, if applicable) or interest caused by the insolvency or negligence or any other act or omission of the trustee or paying agent, if any.

As a condition of its commitment to insure Bonds, Financial Guaranty may be granted certain rights under the FGIC Insured Bond documentation. The specific rights, if any, granted to Financial Guaranty in connection with its insurance of the FGIC Insured Bonds may be set forth in the description of the principal legal documents appearing elsewhere in this Official Statement, and reference should be made thereto.

The FGIC Policy is not covered by the Property/Casualty Insurance Security Fund specified in Article 76 of the New York Insurance Law.

Financial Guaranty Insurance Company

Financial Guaranty, a New York stock insurance corporation, is a direct, wholly-owned subsidiary of FGIC Corporation, and provides financial guaranty insurance for public finance and structured finance obligations. Financial Guaranty is licensed to engage in financial guaranty insurance in all 50 states, the District of Columbia and the Commonwealth of Puerto Rico and, through a branch, in the United Kingdom. Financial Guaranty is a wholly-owned subsidiary of FGIC Corporation, a Delaware corporation.

On December 18, 2003, an investor group consisting of The PMI Group, Inc. ("PMI"), affiliates of The Blackstone Group L.P. ("Blackstone"), affiliates of The Cypress Group L.L.C. ("Cypress") and affiliates of CIVC Partners L.P. ("CIVC") acquired FGIC Corporation (the "FGIC Acquisition") from a subsidiary of General Electric Capital Corporation ("GE Capital"). PMI, Blackstone, Cypress and CIVC acquired approximately 42%, 23%, 23% and 7%, respectively, of FGIC Corporation's common stock. GE Capital retained approximately $234.6 million in liquidation preference of FGIC Corporation's convertible participating preferred stock and approximately 5% of FGIC Corporation's common stock. Neither FGIC Corporation nor any of its shareholders is obligated to pay any debts of Financial Guaranty or any claims under any insurance policy, including the FGIC Policy, issued by Financial Guaranty.

Financial Guaranty is subject to the insurance laws and regulations of the State of New York, where it is domiciled, including Article 69 of the New York Insurance Law ("Article 69"), a comprehensive financial guaranty insurance statute. Financial Guaranty is also subject to the insurance laws and regulations of all other jurisdictions in which it is licensed to transact insurance business. The insurance laws and regulations, as well as the level of supervisory authority that may be exercised by the various insurance regulators, vary by jurisdiction, but generally require insurance companies to maintain minimum standards of business conduct and solvency, to meet certain financial tests, to comply with requirements concerning permitted investments and the use of policy forms and premium rates and to file quarterly and annual financial statements on the basis of statutory accounting principles ("SAP") and other reports. In addition, Article 69, among other things, limits the business of each financial guaranty insurer, including Financial Guaranty, to financial guaranty insurance and certain related lines.

For the years ended December 31, 2003 and December 31, 2002, Financial Guaranty had written directly or assumed through reinsurance, guaranties of approximately $42.4 billion and $47.9 billion par value of securities, respectively (of which approximately 79% and 81%, respectively, constituted guaranties of municipal bonds), for which it had collected gross premiums of approximately $260.3 million and $232.6 million, respectively. For the year ended December 31, 2003, Financial Guaranty had reinsured, through facultative arrangements, approximately 2.0% of the risks it had written.

As of December 31, 2003, Financial Guaranty had net admitted assets of approximately $2.741 billion, total liabilities of approximately $1.587 billion, and total capital and surplus of approximately $1.153 billion, determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities.

The audited financial statements of Financial Guaranty as of December 31, 2003 and 2002, which have been filed with the Nationally Recognized Municipal Securities Information Repositories ("NRMSIRs"), are hereby included by specific reference in this Official Statement. Any statement contained herein under the heading "SECURITY FOR THE NET BILLED BONDS — BOND INSURANCE," or in any documents included by specific reference herein, shall be modified or superseded to the extent required by any statement in any document subsequently filed by Financial Guaranty with such NRMSIRs, and shall not be deemed, except as so modified or superseded, to constitute a part of this Official Statement. All financial statements of Financial Guaranty (if any) included in documents filed by the Issuer with the NRMSIRs subsequent to the date of this Official Statement and prior to the termination of the offering of the 2004 Bonds shall be deemed to be included by specific reference into this Official Statement and to be a part hereof from the respective dates of filing of such documents.

Financial Guaranty also prepares quarterly and annual financial statements on the basis of generally accepted accounting principles. Copies of Financial Guaranty's most recent GAAP and SAP financial statements are available upon request to: Financial Guaranty Insurance Company, 125 Park Avenue, New York, NY 10017, Attention: Corporate Communications Department. Financial Guaranty's telephone number is (212) 312-3000.

Financial Guaranty's Credit Ratings

The financial strength of Financial Guaranty is rated "AAA" by Standard & Poor's, a Division of The McGraw-Hill Companies, Inc., "Aaa" by Moody's Investors Service, and "AAA" by Fitch Ratings. Each rating of Financial Guaranty should be evaluated independently. The ratings reflect the respective ratings agencies' current assessments of the insurance financial strength of Financial Guaranty. Any further explanation of any rating may be obtained only from the applicable rating agency. These ratings are not recommendations to buy, sell or hold the 2004 Bonds, and are 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 2004 Bonds. Financial Guaranty does not guarantee the market price or investment value of the 2004 Bonds nor does it guarantee that the ratings on the 2004 Bonds will not be revised or withdrawn.

Neither Financial Guaranty nor any of its affiliates accepts any responsibility for the accuracy or completeness of the Official Statement or any information or disclosure that is provided to potential purchasers of the 2004 Bonds, or omitted from such disclosure, other than with respect to the accuracy of information with respect to Financial Guaranty or the FGIC Policy under the heading "SECURITY FOR THE NET BILLED BONDS — BOND INSURANCE." In addition, Financial Guaranty makes no representation regarding the 2004 Bonds or the advisability of investing in the 2004 Bonds.

ENERGY NORTHWEST

GENERAL

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington, was organized in January 1957 pursuant to the Act. Energy Northwest was formerly known as Washington Public Power Supply System. The name was officially changed to Energy Northwest on June 2, 1999. Energy Northwest has authority, among other things, to acquire, construct and operate plants, works and facilities for the generation of and transmission of electric power and energy and to issue bonds and other evidences of indebtedness for such purposes. Energy Northwest has the power of eminent domain but is specifically precluded from the condemnation of any plants, works or facilities owned and operated by any city, public utility district or investor-owned utility. Energy Northwest has no taxing power.

Energy Northwest owns and operates Columbia and Packwood which are currently in operation, and have net design electric ratings of 1,153 megawatts and 27.5 megawatts, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, consisting of 49 wind turbines with a maximum generating capacity of approximately 64 megawatts. Energy Northwest also owns and/or has financial responsibility for four nuclear electric generating projects which have been terminated: Projects 1, 3, 4 and 5. Energy Northwest also owns HGP, which ceased operation in 1987, and site restoration activities coordinated with DOE are continuing. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "— Project 1," "— Project 3" and "— Projects 4 and 5."

Each of Energy Northwest's projects is treated and accounted for by Energy Northwest as a separate utility system, with the exception of Projects 4 and 5, which together comprised a single utility system. Under Washington law, a joint operating agency may create separate special funds for each of its utility systems and Energy Northwest has done so. The resolutions of Energy Northwest pursuant to which its various series of bonds are issued provide that the income, receipts and revenues of each utility system are pledged solely to the payment of obligations incurred in connection with that utility system. See Appendix C — "AUDITED FINANCIAL STATEMENTS OF ENERGY NORTHWEST PROJECTS FOR THE YEAR ENDED JUNE 30, 2003" for the audited financial statements of each of Energy Northwest's projects, including the report of the independent auditors, PricewaterhouseCoopers LLP, for the fiscal year ended June 30, 2003.

ENERGY NORTHWEST INDEBTEDNESS

The following table sets forth the principal amounts of revenue bonds and refunding revenue bonds issued by Energy Northwest and outstanding as of May 1, 2004. For information with respect to certain outstanding Promissory Notes of Energy Northwest and Net Billed Bonds to be refunded see "PURPOSE OF ISSUANCE."

Energy Northwest Revenue Bonds
Outstanding as of May 1, 2004

REVENUE BONDS	**PRINCIPAL AMOUNT**
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$948,610,000
Electric Revenue Refunding Bonds	1,032,005,000
TOTAL PROJECT 1	$1,980,615,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	1,351,167,164[(1)]
Electric Revenue Refunding Bonds	777,080,000
Electric Revenue Bonds	41,330,000
TOTAL COLUMBIA	$2,169,577,164
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 907,415,973[(1)]
Electric Revenue Refunding Bonds	1,004,980,000
TOTAL PROJECT 3	$1,912,395,973
TOTAL NET BILLED REVENUE BONDS	$6,062,588,137
Packwood Revenue Bonds [(2)]	$ 3,751,000[(2)]
Nine Canyon Wind Project Revenue Bonds [(2)]	$ 92,395,000[(2)]

(1) Includes $80,545,164 accreted value of Compound Interest Bonds for Columbia and $343,244,973 accreted value of Compound Interest Bonds for Project 3 each as of January 1, 2004.

(2) Bonneville is not a party to any agreements that secure payment of the Packwood Bonds or Nine Canyon Wind Project Bonds.

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 18, consisting of 15 public utility districts and the cities of Richland, Seattle, and Tacoma, all located in the State of Washington. Any public utility district and any municipal entity within the State of Washington authorized to engage in the business of generating or distributing electricity may join Energy Northwest.

Energy Northwest has its principal office in Richland, Washington. The Board of Directors of Energy Northwest is comprised of 18 members, one from each of the member utilities. Pursuant to the Act, the powers and duties of the Board of Directors are limited to (i) final authority on any decision to acquire, construct, terminate or decommission any power plants, works and facilities, except that once such a final decision is made with respect to a nuclear power plant, the Executive Board has authority to make all subsequent decisions regarding such plant; (ii) the election and removal of, and establishment of salaries for, the five members of the Executive Board selected from among the members of the Board of Directors; and (iii) the selection of three of the six members of the Executive Board who are outside directors. All other powers and duties of Energy Northwest, including but not limited to the authority to sell any power plant, works and facilities, are vested in the Executive Board.

The Act provides that five of the members of the Executive Board of Energy Northwest are elected by the Board of Directors from among its members and six are outside directors representative of policy makers in business, finance or science, or having expertise in the construction or management of facilities such as those owned by Energy Northwest. Three of these six outside directors are selected by the Board of Directors and three by the Governor of the State of Washington subject to confirmation by the Washington Senate.

The five members of the Executive Board who are elected from among the Board of Directors serve for four-year terms and may be removed by a majority vote of the Board of Directors. The other members of the Executive Board serve for four-year terms and may be removed by the Governor of the State of Washington for incompetence, misconduct or malfeasance in office; provided, however, the three members appointed by the Governor may be removed without cause prior to their confirmation with the consent of the Washington Senate. The Chief Executive Officer and other staff of Energy Northwest serve at the will of the Executive Board.

EXECUTIVE BOARD

Present Executive Board members are listed below.

Name	Occupation	Term Expires
Edward E. Coates, Chairman	Retired Utility Executive	June 2006
Dan G. Gunkel, Vice Chairman	Public Utility District Commissioner	June 2006
Darrel Bunch, Secretary	Public Utility District Commissioner	June 2006
Amy C. Solomon, Assistant Secretary	Program Officer	June 2005
Margaret Allen	Attorney	June 2004
Tom Casey	Public Utility District Commissioner	June 2006
Vera Claussen	Public Utility District Commissioner	June 2006
Tim Sheldon	Washington State Senator	June 2004
Larry Kenney	Retired Organized Labor Executive	June 2006
Sid W. Morrison	Retired Executive	June 2005
Roger C. Sparks	Public Utility District Commissioner	June 2006

MANAGEMENT

The following is a list of certain key senior staff of Energy Northwest.

Name	Position	Nuclear Industry Experience
Joseph V. Parrish	Chief Executive Officer/Chief Nuclear Officer	33 years
Rodney L. Webring	Vice President, Nuclear Generation	30 years
Dale K. Atkinson	Vice President, Technical Services	26 years
John W. Baker	Vice President, Energy/Business Services/Public Information Officer	33 years
Albert E. Mouncer	Vice President, Corporate Services/ General Counsel/Chief Financial Officer	23 years
Cheryl M. Whitcomb	Assistant to Chief Executive Officer/Chief Knowledge Officer	30 years

EMPLOYEES

Energy Northwest currently employs approximately 1,208 employees. Of these employees, 336 are members of the International Brotherhood of Electrical Workers ("IBEW"), 114 are members of the Paper, Allied Industrial, Chemical & Energy Workers ("PACE") and 7 are members of the Hanford Atomic Metal Trades Council ("HAMTC") unions. The IBEW union members comprise the Administrative, Nuclear, Travelers and Plant bargaining groups, the PACE union members constitute the Security Force bargaining group, and the HAMTC union members comprise part of the Standards Lab Instrument Technicians. The Nuclear, HAMTC and Plant collective bargaining agreements expire on October 1, 2004. The Administrative and Travelers collective bargaining agreements expire on October 30, 2004. The PACE collective bargaining agreement expired on November 2, 2002. Negotiations continue for a new agreement for the PACE bargaining unit. Washington State law provides for binding interest arbitration for the PACE collective bargaining unit. A no-strike clause is included in each of the agreements.

INVESTMENT POLICY

Energy Northwest invests in accordance with the authority provided by the Prior Lien Resolutions and the Electric Revenue Bond Resolutions and its investment policy covers all funds and investment activities under the direct authority of Energy Northwest. This investment policy is approved by the Energy Northwest Executive Board.

Investment securities purchased consist generally of obligations of, or obligations the principal and interest on which is unconditionally guaranteed by, the United States of America or other investment securities permitted by the related Net Billed Resolutions. Current investment policy does not permit the purchase of leveraged or derivative-based investments.

For further information on the types of investments in which Energy Northwest is permitted to invest its funds, see Appendix H-1 — "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS — Investment of Funds (Section 508)" and Appendix H-2 — "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS — Other Funds Established by the Prior Lien Resolutions; Flow of Revenues."

THE COLUMBIA GENERATING STATION

Description

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 DOE's Hanford Reservation. Its former name, Nuclear Project No. 2, was officially changed to the Columbia Generating Station on April 27, 2000. 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 electric 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. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS."

Columbia consists of the following structures: the reactor building, the radioactive waste building, the turbine-generator building, the diesel generator building, the service building, six mechanical-draft evaporative cooling towers, the circulating water pumphouse and the river makeup water pumphouse. Makeup water to replace evaporative losses is obtained from the Columbia River by means of three makeup water pumps. Emergency power is supplied to Columbia by diesel generators sized to sustain all essential plant loads without the need for outside power sources. Columbia also includes the Independent Spent Fuel Storage Installation facility. For additional information concerning the Independent Spent Fuel Storage Installation facility, see "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION—Nuclear Fuel" below.

Columbia also includes the plant engineering center and other office and support facilities located adjacent to the main plant, the plant support facility located one mile southwest of the main plant and various administrative service buildings located in Richland, Washington, approximately ten miles from the site.

Low-level radioactive waste generated at Columbia is disposed of at a commercial facility located on the Hanford Reservation.

Management Discussion of Operations

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has an amended maintenance, operating, outage, fuel and capital budget for Columbia of $210.4 million during the 2004 fiscal year.

The cost of production, using industry standard methodology (such cost calculation methodology includes general and administration and capital, but excludes debt service, taxes, depreciation and decommissioning costs) of Columbia electricity is projected at $21.85 per megawatt-hour during the 2004 fiscal year. This cost is lower than the $30.10 per megawatt-hour for the

2003 fiscal year since the 2003 fiscal year included a bi-annual refueling outage as well as certain other forced outages discussed below. These costs are about average for the nuclear industry. Energy Northwest will continue to place a high priority on cost-containment.

Energy Northwest continues to focus on plant reliability and availability and increasing gross plant capacity as the primary factors to reduce the cost of power.

While Energy Northwest intends to operate Columbia a greater percentage of the time, Energy Northwest has also evaluated plans to increase the gross capacity of the plant. Engineers evaluated a proposal that could increase the plant's name plate capacity to about 1,350 megawatts - a 12.5% increase in power. Based on current market conditions and other technical considerations, this effort has been put on hold. Initiatives to reduce losses of generation, such as reducing outage length and reducing or eliminating the occurrences of forced outages, are being evaluated and implemented.

To increase the value of the plant over time, engineers now are working on a proposal to extend Columbia's 40-year operating license by 20 years, from 2023 to 2043. The NRC established a protocol to handle license extension requests, and has granted 25 such requests since 2000. The Executive Board will determine whether to apply for an extension.

Energy Northwest also has pursued several other ventures beyond the operation of Columbia - all of which are designed to relieve, in part, fixed-cost pressures on Columbia. Contracts to outsource engineering and testing services have allowed Energy Northwest to better use resources originally dedicated to Columbia.

Operating Performance

Columbia received a full operating license in March 1984, commenced commercial operation in December 1984 and has been in operation since that time. Since commencing commercial operation, Columbia has operated at a cumulative capacity factor of 67.6% and has generated 126,076,194 megawatt hours (net of station use) of electric power through April 2004.

Successful implementation of employee performance enhancement initiatives at Columbia has produced significant positive results in plant performance since 1995. Calendar year 2002 was the best generating calendar year at Columbia since commencing commercial operation, eclipsing the previous record in 2000. In fiscal year 2002, Columbia produced 9,262 million kilowatt hours of electric power while attaining a plant capacity factor of 92.0% and a plant availability factor of 95.4%. In fiscal year 2003, Columbia produced 7,738 million kilowatt hours of electric power while attaining a plant capacity factor of 78.5% and a plant availability factor of 81.0%. This decline in generation was the result of three forced outages during fiscal year 2003 along with the scheduled refueling outage which occurs every two years. The outages that caused the loss of generation were: (1) a forced outage due to a diesel generator bearing problem; (2) a forced outage due to a condenser leak; (3) a longer than planned refueling outage (50 days versus 34 days); and (4) a forced outage due to a transformer electrical short. Columbia has been on-line continuously since July 2003.

Annual Costs

Annual costs for Columbia based on the audited financial statement presentation format for fiscal years ended June 30, 2002 and 2003 are shown below. The information is developed on a cost basis with depreciation calculated on the straight line method by major components based on expected useful life.

Statement of Operations(1)
(Dollars in Thousands)

Cost Category	FY 2003	FY 2002
Operations, Maintenance and Overhead	$159,312	$144,588
Nuclear Fuel Burnup	27,061	30,311
Spent Fuel Disposal Fee	7,253	8,487
Generation Taxes	2,237	3,198
Decommissioning	26,505	16,408
Depreciation and Amortization	79,528	96,171
Investment Income	(6,751)	(11,540)
Interest Expense and Discount Amortization	119,666	121,584
Other Expense/(Revenue)	(1,765)	(2,212)
Total Costs	$413,046	$406,995
Net Generation (Million kWhs) (unaudited)	7,738(2)(3)	9,262(2)

(1) Amounts derived from audited Energy Northwest financial statements.
(2) Includes credit for "Economic Dispatch" of 122 million kWhs and 336 million kWhs for fiscal years 2003 and 2002, respectively. Total energy not generated due to reductions requested by Bonneville is referred to by Bonneville as "Economic Dispatch."
(3) Total costs increased in fiscal year 2003 from fiscal year 2002 as a result of decreased generation due to outages.

Capital Improvements

Since entering commercial operation, Energy Northwest has been making capital improvements to Columbia. In fiscal year 2003, the cash spent on capital improvements was $18.5 million. The proceeds of the Columbia 2004-C Bonds are to pay a majority of the costs of capital improvements during fiscal years 2004 and 2005. See "PURPOSES OF ISSUANCE – Columbia 2004-C Bonds".

Nuclear Regulatory Commission Actions

The NRC is a Federal agency that regulates the design, construction, licensing and operation of nuclear power plants. Once a plant is licensed, one of the major activities of the NRC is the inspection of plant management and operation. The NRC develops policies and administers programs for inspecting licensees to ascertain whether they are complying with NRC regulations, rules, orders and license provisions. The NRC has the authority to suspend, revoke or modify the operating license of commercial nuclear plants to correct deficiencies.

Energy Northwest's activities related to operation and support of Columbia, like those of other licensed nuclear plant operators, are periodically inspected by the NRC. In addition, the NRC normally maintains two on-site resident inspectors who monitor plant activities on a day-to-day basis.

In addition to the day-to-day resident inspector activities, the NRC assesses the performance of nuclear plant operators, including Columbia, by a process known as the Reactor Oversight Process (the "ROP"). The ROP is built upon a framework directly linked to the NRC's mission to protect public health and safety. The framework includes seven cornerstones of safety. Within each cornerstone, a broad sample of information on which to assess plant operator performance in risk-significant areas is gathered. The information is collected from plant performance indicator data submitted by the plant operator and from NRC risk-informed baseline inspections.

The ROP calls for focusing inspections on activities where the potential risks are greater, applying greater regulatory attention to facilities with performance problems and reducing regulatory attention of facilities that perform well, using objective measurements of the performance of nuclear power plants whenever possible, giving the nuclear industry and the public timely and understandable assessments of plant performance, avoiding unnecessary regulatory burdens of nuclear facilities and responding to violations of regulations in a predictable and consistent manner that reflects the safety impact of the violations.

To monitor these seven cornerstones, the NRC assigned colors of green, white, yellow or red to specific performance indicators and inspection findings. For performance indicators, a green coding indicates performance within an expected performance level in which the related cornerstone objectives are met; white coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; yellow coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin; and red coding indicates a significant reduction in safety margin in the area measured by that performance indicator. For inspection findings, green findings are indicative of issues that, while they may not be desirable, represent very low safety significance. White findings indicate issues that are of low to moderate significance. Yellow findings are issues that are of substantial safety significance. Red findings represent issues that are of high safety significance with a significant reduction in safety margin.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary. The Action Matrix Summary reflects overall plant performance which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance Columns.

Best performing plants are included in the Licensee Response Column where routine inspector and staff interaction is the norm. The next level of performance is the Regulatory Response Column, which includes plants that have no more than two white inputs in different Cornerstones of safe operation. Plants in this column are subject to NRC inspection follow-up of utility corrective actions. There are three remaining Response Columns, including the Unacceptable Performance Column, which includes plants that are not permitted to operate.

The NRC's Fourth Quarter 2003 Regulatory Oversight Process Summary lists 75 plants, including Columbia, in the Licensee Response Column, 22 plants in the Regulatory Response Column and five plants in the next two lower columns. There are no plants currently included in the Unacceptable Performance Column. One plant is in a shutdown condition and requires NRC approval to restart.

Institute of Nuclear Power Operations

The nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. INPO's mission is to promote the highest levels of safety and reliability in the operation of nuclear electric generating plants. All United States utilities that operate commercial nuclear power plants are INPO members. INPO has conducted plant evaluations of Columbia approximately every 12 to 18 months since the initial date of commercial operation.

INPO performed an evaluation of Columbia in October 2002. A number of beneficial practices and accomplishments were noted, as well as some areas for improvement. Among the areas in need of improvement, the most significant were equipment performance and material condition, outage performance and sustaining performance. Based on the results of the plant evaluation, INPO issued an overall rating of 2, indicating that overall performance is exemplary. INPO ratings range from 1 to 5, with 1 being the highest achievable rating. The next plant evaluation is planned for early 2005.

Permits and Licenses

Energy Northwest has obtained all permits and licenses required to operate Columbia, including an NRC operating license which expires in 2023. See "— Nuclear Regulatory Commission Actions" above for a discussion of NRC activities related to Columbia.

A site certification agreement for Columbia was executed with the State of Washington in May 1972. The site certification requires Energy Northwest to, among other things, monitor the environmental effects of plant construction and plant operation, comply with standards set for the consumption and discharge of water and for discharges to the air, and develop an effective emergency plan. The state has also issued a National Pollutant Discharge Elimination System ("NPDES") permit and the necessary Certificate of Water Right. The Certificate of Water Right expires when use ceases. The NPDES permit is effective until April 2006 and is renewable for five-year terms thereafter. The Washington State Department of Natural Resources has entered into a lease with Energy Northwest, which expires in March 2005, for that portion of the bed of the Columbia River which encompasses the plant intake and discharge facilities. Energy Northwest anticipates renewal of this lease in accordance with the right-of-renewal provisions contained therein. The Corps has issued a permit for construction and maintenance of the now completed river facilities. Energy Northwest has an interim status permit for storage of mixed radioactive and hazardous wastes. The processing of a final Resource Conservation and Recovery Act ("RCRA") permit has been suspended by the State of Washington pending a national review of mixed waste disposal capacity. Energy Northwest continues to manage its mixed wastes in accordance with the conditions of the interim status permit.

Nuclear Fuel

The supply of nuclear fuel assemblies requires four basic activities prior to insertion of the fuel assemblies into a nuclear reactor. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexaflouride, enrichment of the uranium hexaflouride and fabrication of the enriched uranium in the form of uranium oxide pellets into finished fuel assemblies.

The initial core of fuel assemblies was fabricated by General Electric and loaded into the reactor in December 1983. A portion of the fuel was then replaced during refueling outages so that by mid-1992 all of the initial core fuel had been replaced with reload fuel assemblies.

Since 2002 reload fuel design and fabrication services for three "firm" reloads has been provided pursuant to a contract with Framatome ANP, Inc. Said contract also provides for two optional reloads.

Columbia had historically operated on a 12 month fuel cycle but in 1998 a decision was made to transition to a 24 month fuel cycle. A 24 month fuel cycle eliminates refueling outages every other year and results in increased average generation. After two transition cycles totaling approximately 36 months in length, the first 24 month cycle began in 2001.

To meet the enriched uranium requirements for the reload fuel assemblies, Energy Northwest purchases uranium in various forms and holds them in inventory until needed for fuel fabrication. However, some or all of this inventory is being or might be loaned. Currently, Energy Northwest's inventory of natural uranium hexaflouride is sufficient for plant requirements through 2006.

Energy Northwest has a contract with DOE that requires the DOE to accept title and dispose of spent nuclear fuel. For this future service, Energy Northwest pays a quarterly fee based on about one mill per kilowatt-hour of net electricity generated and sold from Columbia ($7.3 million for the 12 months ended June 30, 2003). To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating a proposed site in Nevada for an underground geological repository. Although courts have ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, the repository is not expected to be in operation before 2010. Once DOE begins to accept spent fuel, it will accept the oldest spent fuel first, on a national basis. Because Columbia is a relatively young plant, DOE does not plan to accept any spent fuel from Columbia during the first ten years of repository operation.

Columbia had sufficient capacity in the plant to accommodate all its spent fuel discharges through calendar year 2003. To accommodate spent fuel discharges after 2003, Energy Northwest constructed the Independent Spent Fuel Storage Installation ("ISFSI") facility, to store spent fuel in commercially available dry storage casks on concrete pads at the plant site. Energy Northwest has a contract for a dry storage cask system. Initial capital costs of the ISFSI facility were approximately $34.5 million with additional costs for dry storage casks projected at approximately $25 million through 2010. The facility will be expanded in increments as needed in the future.

Decommissioning

The NRC has defined decommissioning as actions taken which result in the release of the property for unrestricted use and termination of the nuclear power plant operating license. Currently, the nuclear industry recognizes three alternative methods (decontamination, safe storage and entombment) to decommission a nuclear power plant. Energy Northwest's decommissioning plan is based on the safe storage method of decommissioning. Safe storage entails placing and maintaining the nuclear facility in a condition that allows it to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use. The NRC requires that this deferred decontamination period be no longer than 60 years.

Energy Northwest's current estimate of Columbia decommissioning costs is approximately $608 million (in 2003 dollars). This estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia. Additionally, site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council ("EFSEC"). Energy Northwest submitted a site restoration plan for Columbia that was approved by EFSEC on June 12, 1995. Energy Northwest's current estimate of Columbia's site restoration costs is approximately $65 million (in 2003 dollars).

The current funding plan requires annual deposits through fiscal year 2024, the estimated end of commercial operation of Columbia. The plan assumes that such deposits will grow at a 2% real rate of return and that Columbia will be placed in an approximately 60-year safe storage until 2085, at which time decontamination and dismantlement will be completed. Over the life of the fund, deposits and the earnings related to the reinvestment thereof are expected to provide sufficient funds to cover the cash flow requirements to decommission Columbia. This plan will be re-examined every year and modified, if necessary, to assure that the projected fund balance complies with the then current estimates and NRC requirements. Payments to the decommissioning trust fund have been made since 1985 and the balance of cash and investment securities in the fund as of February 29, 2004, totaled approximately $82.9 million. A separate fund has been established for site restoration. The balance of this fund as of February 29, 2004, totaled approximately $9.1 million. These amounts are held in an external decommissioning trust fund in accordance with NRC requirements and are administered by Bonneville.

Insurance

Energy Northwest maintains a risk management and insurance program which incorporates a combination of self-insurance, commercial insurance and nuclear property and liability insurance. Energy Northwest's basic risk management philosophy is to pay normal and expected losses from revenues and to purchase insurance to cover catastrophic losses. Energy Northwest, as a licensee of the NRC, is subject to retrospective premiums for nuclear liability and property insurance. Claims relating to Columbia or Project 1 that are not covered by insurance are paid from revenues under the related Project Net Billing Agreements.

Commercial liability insurance is purchased to cover all Energy Northwest premises and operations. This insurance provides coverage for injury or damage arising from non-nuclear accidents or occurrences. Energy Northwest maintains nuclear insurance in accordance with regulatory and Energy Northwest risk management policies.

Nuclear liability insurance covers third party injury or damage arising out of a nuclear incident and is required under the Price Anderson Act, enacted in 1957 as an amendment to the Atomic Energy Act (as amended, "Price Anderson"). Price Anderson provides financial protection for the public in the event of bodily injury or property damage caused by a commercial nuclear incident. The law had been extended three times and was subject to renewal in August 2002. Legislation was signed by the president in December 2002, which reauthorized Price Anderson through December 2004.

In accordance with Price Anderson, the nuclear liability exposures of Columbia are covered through the purchase of commercial nuclear liability insurance. This policy carries a limit of $300 million with no deductible and forms the primary layer of protection. The excess layer of protection above this amount is provided through a mandatory industry self-insurance program featuring an assessment provision to all licensed nuclear power reactors. This excess layer amount is just over $10.56 billion, based on 105 licensed reactors, multiplied by a current maximum retrospective assessment of $100.59 million per reactor, per any one nuclear incident. Therefore, the total public liability coverage available per incident is approximately $10.86 billion. It is important to note that in the event there is an incident triggering an assessment, the maximum annual deferred premium assessment would be $10 million per incident. This assessment is payable under the Columbia Net Billing Agreements.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by Energy Northwest and Bonneville. The total amount of insurance purchased is currently $2.25 billion. The deductible for this coverage is $5 million per occurrence. Additionally, Bonneville purchases business interruption coverage which pays $3.5 million per week, following a 12 week deductible period for the first year and then for the next 110 weeks, pays 80% of this amount for a maximum indemnification of $490 million. The limits of liability and policy coverage for Columbia meet all legal requirements for a nuclear power production facility and are consistent with that purchased by other nuclear utilities relative to similar circumstances and exposures.

PACKWOOD LAKE HYDROELECTRIC PROJECT

Energy Northwest owns and operates Packwood, a hydroelectric generating facility with a nameplate rating of 27.5 megawatts. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles south-southeast of Seattle, Washington. Packwood was granted a FERC operating license on March 1, 1960, and began commercial operation in June 1964. The initial FERC license has a duration of 50 years and expires on February 28, 2010. Based on the existing FERC licensing process, Energy Northwest initiated relicensing efforts in fiscal year 2004.

Average annual generation for the facility is 92,000 megawatt-hours. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs, including debt service on the Packwood Bonds. Until October 2002, the electric power produced at the facility was sold to Bonneville for distribution to the original 12 public utilities who are the Packwood participants. The Packwood participants are required to pay their share of the annual budget of the project, which includes debt service on the Packwood Bonds, whether or not the project is producing power or capable of producing power. As of November 2002, the power produced is being sold directly to two of those participants, Benton County PUD and Franklin County PUD. The one year agreements with Benton County PUD and Franklin County PUD expire on November 1, 2004.

NINE CANYON WIND PROJECT

Energy Northwest previously completed construction of the first phase of a wind energy project, capable of generating 48.1 megawatts of electricity. The project is located on leased land, near Kennewick, Washington, and includes 37 wind turbines. Each turbine has a power generating capacity of 1,300 kilowatts. The turbines were manufactured by BONUS Energy A/S, a Denmark corporation. In early November 2001, Energy Northwest issued approximately $70.7 million of bonds to finance the acquisition, development and construction costs of the project. The project is a separate system of Energy Northwest and the bonds are secured by, and payable solely from, the revenues derived by Energy Northwest under power purchase agreements executed with public utility purchasers, including Energy Northwest, which has acquired a portion of the Phase I capability for station use by Columbia. Energy Northwest recently completed construction of the second phase of the Nine Canyon Wind Energy Project, capable of generating 15.6 megawatts of electricity. Phase II is located on the same site as Phase I, and includes 12 identical wind turbines. In May 2003, Energy Northwest issued approximately $22 million of bonds to finance the acquisition, development and construction costs of Phase II of the project. The bonds are secured in the same manner as the Phase I bonds. Energy Northwest did not acquire any portion of the Phase II capability. The purchasers are required to pay their share of the annual budget of the project, which includes debt service on the related bonds, whether or not the project is operating or capable of operating. Power costs for the project to be billed to the purchasers are expected to be in the range of 3.5 cents per kilowatt hour to 3.9 cents per kilowatt hour during the first five fiscal years of operation and the cost allocable to Energy Northwest would constitute an operating expense of Columbia. See "ENERGY NORTHWEST — THE COLUMBIA GENERATING STATION — Management Discussion of Operations" in this Official Statement.

PROJECT 1

Project 1 is a 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 and was terminated in May 1994. The Project 1 Project Agreement and the Project 1 Net Billing Agreements ended upon termination of Project 1, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement. The Project 1 Post Termination Agreement also facilitates the administration, budgeting and payment processes post termination. 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. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with asset sales and planning for the demolition and site restoration activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements and monies held in the Project 1 Construction Fund.

Site restoration requirements for Project 1 (as well as Project 4) are governed by a site certification agreement between Energy Northwest and the State of Washington and regulations adopted by EFSEC and a lease agreement with DOE.

Energy Northwest, Bonneville, EFSEC and DOE executed an agreement concerning site restoration of Projects 1 and 4 in December 2003. The agreement provides that final remediation may be deferred up to 23 years and completion of final remediation within about three years after the end of the deferral period. Near term remediation is to be completed within two years to implement specified health, safety, and environmental protection cleanup activities. This near term work scope is currently estimated to cost $4 million and is scheduled for completion in 2005.

The agreement requires Bonneville to fund this site remediation plan for Projects 1 and 4 and the cost for both sites' remediation is estimated at $45 million (calendar year 2003 dollars). Bonneville has placed funds in an external interest-bearing account in order to have sufficient funds for the eventual final remediation. Bonneville's site remediation obligation, even if reuse of the sites and structures does not occur, is not conditioned on the adequacy of funds in the trust account.

In January 2004, Energy Northwest adopted a policy statement for the potential reuse of Projects 1 and 4. This policy provides for the continued safe, environmentally sound, and cost efficient operation of the Columbia Generating Station in the best interests of Energy Northwest, Bonneville, public power, and the region's ratepayers. Any proposed uses, whether public or private, will be subject to contributing to the goals of assuring public health and safety, reducing Columbia's cost of power, reducing Projects 1 and 4 costs, and providing for local economic development.

PROJECT 3

Project 3 is a partially complete nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington and was terminated in June 1994. The Project 3 Project Agreement and the Project 3 Net Billing Agreements ended upon termination of Project 3, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement. The Project 3 Post Termination Agreement also facilitates the administration, budgeting and payment processes post termination.

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 3 in its entirety. During 1995, a group from Grays Harbor County, Washington, interested in local economic development, formed the Satsop Redevelopment Project. The Satsop Redevelopment Project is a coalition of governments established by inter-local agreement between Grays Harbor County, the Port of Grays Harbor and Public Utility District No. 1 of Grays Harbor County. The transfer of the Project 3 site properties and facilities (other than the Satsop CT site) was made in 1999 to said local public agencies for purposes of economic development.

PROJECTS 4 AND 5

Projects 4 and 5 were terminated in January 1982. The Project 4/5 Bonds went into default on July 22, 1983. Subsequent to extended litigation and ultimate settlement, all trusts created under the resolution authorizing the Project 4/5 Bonds were terminated and Energy Northwest and the trustee under said resolution were released from all of their obligations thereunder.

HANFORD GENERATING PROJECT

Energy Northwest owns HGP, which is located on DOE's Hanford Reservation, approximately 140 miles southeast of Seattle, Washington. HGP was an 860 megawatt plant that operated from April 1966 through January 1987 and generated 65.9 billion kilowatt-hours of electricity. Preservation of HGP physical assets was discontinued in September 1993. Energy Northwest and DOE reached agreement in May 2002 concerning DOE's liability for radioactive contamination and its related impacts on HGP site restoration. Per the agreement, DOE will reimburse Energy Northwest for all cost impacts related to the radioactive contamination of the piping and equipment. Activities are currently underway to complete restorations by March 2005.

All basic administrative costs incurred from September 1993 through June 1999 were paid from monies held in the HGP Revenue Fund and all such costs subsequently incurred and to be incurred in the future have been and will be paid from monies held in the Project 1 Revenue Fund.

OTHER ACTIVITIES

Satsop CT

In 1990, the Board of Directors of Energy Northwest voted to study the siting of a combustion turbine power plant at the Projects 3 and 5 site. Beginning in 1992, Energy Northwest submitted a series of proposals to Bonneville in response to Bonneville's solicitations for new generating resources. In June 1993, Bonneville notified Energy Northwest that Energy Northwest's combustion turbine, known as the Satsop CT, was selected as one of three combustion turbine power plants to be designed and permitted and held as an "option" under Bonneville's Resource Contingency Program. All required environmental studies and permit applications for two combustion turbine power plant units and all state and federal permits and environmental impact statements had been approved or obtained.

During 2000, because of a shortage of power on the West Coast, several energy companies approached Energy Northwest about purchasing the Satsop CT site. In response to Energy Northwest's solicitation of proposals, Duke Energy Grays Harbor LLC ("Duke Grays Harbor"), an unregulated subsidiary of Duke Energy, submitted a proposal that was approved by Energy Northwest's Executive Board on January 3, 2001. The purchase agreement with Duke Grays Harbor, signed on January 11, 2001, provides for Energy Northwest to receive $10 million in payment for the site or, in the alternative, $5 million if it successfully negotiates a contract with Duke Grays Harbor to operate the first 500 megawatt natural gas-fired power plant to be completed on the site. Energy Northwest has been retained to operate the first power plant on the site for an initial period of five years and has received the $5 million payment. Under the contract, the maximum liability of Energy Northwest is limited to the net income received from Duke Grays Harbor for the preceding 12-month period, with an aggregate liability of up to $1 million for the term of the contract. On August 26, 2002, Duke Grays Harbor made the decision to put the project on hold.

Resource Development

Several years ago, Energy Northwest set out to develop new sources of electricity generation and provide energy and environmental related services to meet the needs of its member utilities and the region. Since 1992, Energy Northwest has provided a wide range of chemical analysis and environmental monitoring services to utility, municipal, commercial, and nuclear customers. Energy Northwest is a founding member of NoaNet, offering access to a fiber-optic cable network licensed from Bonneville and other broadband providers. Energy Northwest is actively investing in emerging technologies through its support of the Applied Process Engineering Laboratory, currently in its sixth year of operation. Energy Northwest has begun the search for biomass generating locations, adhering to its commitment to develop alternative power resources.

The Energy Northwest Board of Directors approved a second wind power project in April 2002. The Zintel Canyon Wind Project is planned to be located adjacent to the Nine Canyon Wind Project and has a potential capacity of about 25 megawatts. The Project is in the early planning stages. Studies necessary to determine project feasibility and utility customer interest are underway.

All of these current and future Energy Northwest initiatives to develop new sources of electricity generation and related energy and environmental services have been or will be funded from sources other than Bonneville, the Net Billing Agreements or Projects 1, 3 and Columbia.

Net Billed Projects Litigation and Claims

The following is a discussion of litigation and claims relating to the Net Billed Projects to which Energy Northwest is a party:

Durametal Brake Company v. Energy Northwest. This is an action filed by Durametal Brake Company, LLC ("DuraBrake") versus Energy Northwest in Benton County Superior Court arising out of a landlord-tenant dispute relating to DuraBrake's leasing of an empty warehouse from Energy Northwest. This dispute relates to the leasehold agreement and commitments relating to the provision of upgraded electrical service to the warehouse. DuraBrake was a start-up business, attempting to develop a market in brake drum manufacturing. Following its inability to successfully conduct operations, DuraBrake filed a complaint for damages for breach of contract, tortious breach of contract, repudiation/breach of lease agreement, and retaliatory eviction in violation of public policy and tortious interference with business expectancy. DuraBrake engaged an expert who offered an opinion that DuraBrake had suffered damages in excess of $10 million. Energy Northwest in its answer to the claims brought by DuraBrake has denied the same. This matter is not currently set for trial and the outcome of the lawsuit cannot be predicted at this time.

Washington State Department of Revenue and General Electric. This is a contingent claim for taxes owed to the Washington State Department of Revenue for the period of 1995 through 2001. Energy Northwest has an agreement with General Electric that provides Energy Northwest the right to purchase services and goods from General Electric at a discount. The Washington State Department of Revenue has completed two separate audits of General Electric covering 1995 through 2001. The Department of Revenue has assessed sales tax and business and occupation tax on sales made by General Electric to Energy Northwest under its agreement. The issue is whether the taxes are owed on the full price of the goods or service or on the discounted price. The Department of Revenue has asserted that the "discount" is a cash item and that sales tax is due on the gross sales price. The assessment against General Electric is in the aggregate amount of $5,612,447. Contract language in the Energy Northwest and General Electric agreement requires Energy Northwest to indemnify General Electric for additional tax liability arising out of the discount program. Energy Northwest contests the Department of Revenue's assertions and expects to assert defenses that mitigate both the amount and likelihood of an adverse judgment in this matter. The outcome of this matter cannot be predicted at this time.

LEGAL MATTERS

The approving opinion of Preston Gates & Ellis LLP, Bond Counsel to Energy Northwest, as to the legality of the 2004 Bonds will be in substantially the forms appended hereto in Appendix D-1 — "PROPOSED FORMS OF OPINIONS OF BOND COUNSEL." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the exclusion of the interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds from the gross income of the owner thereof for federal income tax purposes will be in substantially the form appended hereto in Appendix E — "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL."

Bond Counsel will also render a supplemental opinion with respect to the validity and enforceability of the Net Billing Agreements and the Assignment Agreements. As to the due authorization, execution and delivery of such Net Billing Agreements and the Assignment Agreements by Bonneville and certain other matters relating to Bonneville, Bond Counsel will rely on the opinion of Bonneville's General Counsel. In rendering its opinion with respect to the Net Billing Agreements, Bond Counsel will assume, among other things, (1) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (2) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreements to which such Participant is a party and that all assignments of any Participants' obligations under the Net Billing Agreements were properly done and (3) with respect to the Participants' obligations under the Net Billing Agreements, no conflict or violations under applicable law. In rendering its opinion as to the enforceability of the Net Billing Agreements against the Participants, Bond Counsel has assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations under, the Net Billing Agreements and Assignment Agreements and such opinion does not address the effect on the enforceability against the Participants if Bonneville is no longer obligated under the Net Billing Agreements and Assignment Agreements or of nonperformance thereunder by Bonneville. The assumption in the prior sentence does not affect Bond Counsel's opinion as to the enforceability of the Net Billing Agreements and Assignment Agreements against Bonneville. In the event a Participant's obligations under the Net Billing Agreements are no longer enforceable against such Participant, it is the opinion of Bond Counsel that Bonneville is obligated under the Net Billing Agreements, the Assignment Agreements and the 1989 Letter Agreement to pay to Energy Northwest the amounts required to be paid by such Participant under the Net Billing Agreement. A copy of the proposed form of supplemental opinion of Bond Counsel is appended hereto in Appendix D-2 — "PROPOSED FORMS OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL."

See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Assignment Agreements" for a discussion of Bonneville's agreement to pay directly to Energy Northwest certain amounts which are not paid by a Participant and for a discussion of certain of Bonneville's obligations under the Assignment Agreements.

Certain legal matters, including the enforceability against Bonneville of the Net Billing Agreements and the Assignment Agreements relating to Project 1, Columbia and Project 3, will be passed upon for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters.

TAX MATTERS

Tax Exemption - Series 2004-A Bonds and Columbia 2004-C Bonds

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, (a) interest on the Series 2004-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and (b) interest on the Columbia 2004-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act and Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code"). Special Tax Counsel is of the further opinion that interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. In rendering its opinion, Special Tax Counsel has relied on the opinion of Bond Counsel as to the validity of the Series 2004-A Bonds, validity of the Columbia 2004-C Bonds and the due authorization and issuance of these Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E — "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL."

Series 2004-A Bonds and Columbia 2004-C Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a purchaser's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such purchaser. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The 1986 Act, the 1954 Code and the 1986 Code impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series 2004-A Bonds and the Columbia 2004-C Bonds. Energy Northwest and Bonneville have made certain representations and have covenanted to comply with certain restrictions designed to ensure that interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of these Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring) after the date of issuance of the Series 2004-A Bonds and the Columbia 2004-C Bonds may adversely affect the value of, or the tax status of, interest on these Bonds.

Certain agreements, requirements and procedures contained or referred to in the Net Billed Resolutions, as applicable, the Tax Matters Certificates to be executed and delivered by Energy Northwest and by Bonneville simultaneously with the issuance of the Series 2004-A Bonds and the Columbia 2004-C Bonds, and other relevant documents may be changed and certain actions (including without limitation defeasance of the 2004-A Bonds or the Columbia 2004-C Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. Special Tax Counsel expresses no opinion as to any Series 2004-A Bond or any Columbia 2004-C Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice or approval of counsel other than Orrick, Herrington & Sutcliffe LLP.

Although Special Tax Counsel is of the opinion that interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, these Bonds may otherwise affect a Beneficial Owner's federal or state tax liability. The nature and extent of these other tax consequences will depend upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel expresses no opinion regarding any such other tax consequences.

The opinion of Special Tax Counsel is based on current legal authority and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2004-A Bonds and the Columbia 2004-C Bonds for federal income tax purposes. It is not binding on the IRS or the courts. Special Tax Counsel's engagement with respect to the 2004 Bonds ends with the issuance of the 2004 Bonds, and, unless separately engaged, Special Tax Counsel is not obligated to defend the tax-exempt status of the Series 2004-A Bonds and the Columbia 2004-C Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than Energy Northwest, including Beneficial Owners, will have little if any right to participate in the examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which Energy Northwest or Bonneville legitimately disagree, may not be practical. If such a situation arises, Energy Northwest, Bonneville or Beneficial Owners of the Series 2004-A Bonds or the Columbia 2004-C Bonds may incur significant expense, loss of market value to the Beneficial Owners, or both.

Future legislation, if enacted into law, or clarification of the 1954 Code or the 1986 Code may cause interest on the Series 2004-A Bonds and the Columbia 2004-C Bonds to be subject, directly or indirectly, to federal income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislation or clarification of the 1954 Code or the 1986 Code may also affect the market price for, or marketability of, the Series 2004-A Bonds and the Columbia 2004-C Bonds. Prospective purchasers of these Bonds should consult their own tax advisors regarding any pending or proposed federal tax legislation, as to which Special Tax Counsel expresses no opinion.

Tax Status of the Series 2004-B (Taxable) Bonds

In the opinion of Special Tax Counsel, interest on the Series 2004-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the 1986 Code. Special Tax Counsel expresses no opinion regarding any other federal or state tax consequences relating to the ownership or disposition of, or the accrual or receipt of interest on, the Taxable Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E — "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL."

The following is a summary of certain of the United States federal income tax consequences of the ownership of the Series 2004-B (Taxable) Bonds as of the date hereof. Each prospective investor should consult with its own tax advisor regarding the application of United States federal income tax laws, as well as any state, local, foreign or other tax laws, to its particular situation.

This summary is based on the 1986 Code, as well as Treasury regulations and administrative and judicial rulings and practice. Legislative, judicial and administrative changes may occur, possibly with retroactive effect, that could alter or modify the continued validity of the statements and conclusions set forth herein. This summary is intended as a general explanatory discussion of the consequences of holding the Series 2004-B (Taxable) Bonds generally and does not purport to furnish information in the level of detail or with the investor's specific tax circumstances that would be provided by an investor's own tax advisor. For example, it generally is addressed only to original purchasers of the Series 2004-B (Taxable) Bonds that are "U.S. holders" (as defined below), deals only with Series 2004-B (Taxable) Bonds held as capital assets within the meaning of Section 1221 of the 1986 Code and does not address tax consequences to holders that may be relevant to investors subject to special rules, such as individuals, trusts, estates, tax-exempt investors, foreign investors, cash method taxpayers, dealers in securities, currencies or commodities, banks, thrifts, insurance companies, electing large partnerships, mutual funds, regulated investment companies, real estate investment trusts, Financial Asset Securitization Investment Trusts, S corporations, persons that hold Series 2004-B (Taxable) Bonds as part of a straddle, hedge, integrated or conversion transaction, and persons whose "functional currency" is not the U.S. dollar. In addition, this summary does not address alternative minimum tax issues or the indirect consequences to a holder of an equity interest in a holder of Series 2004-B (Taxable) Bonds.

As used herein, a "U.S. holder" is a "U.S. person" that is a beneficial owner of a Taxable Bond. A "non-U.S. investor" is a holder (or beneficial owner) of a Series 2004-B (Taxable) Bond that is not a U.S. Person. For these purposes, a "U.S. person" is a citizen or resident of the United States, a corporation or partnership created or organized in or under the laws of the United States or any political subdivision thereof (except, in the case of a partnership, to the extent otherwise provided in Treasury regulations), an estate the income of which is subject to United States federal income taxation regardless of its source or a trust if (i) a United States court is able to exercise primary supervision over the trust's administration and (ii) one or more United States persons have the authority to control all of the trust's substantial decisions.

The Series 2004-B (Taxable) Bonds will be treated, for federal income tax purposes, as a debt instrument. Accordingly, interest will be included in the income of the holder as it is paid (or, if the holder is an accrual method taxpayer, as it is accrued) as interest.

Premium. Holders of the Series 2004-B (Taxable) Bonds that have a basis in the Series 2004-B (Taxable) Bonds greater than the principal amount of the Series 2004-B (Taxable) Bonds should consult their own tax advisors with respect to whether they should elect to amortize such premium under section 171 of the 1986 Code.

Original Issue Discount. The Series 2004-B (Taxable) Bonds might be issued with original issue discount ("OID"). A holder of a Series 2004-B (Taxable) Bond will be required to include any OID in gross income as it accrues under a constant yield method, based on the original yield to maturity of the Series 2004-B (Taxable) Bond. Thus, the holders of such Series 2004-B (Taxable) Bonds will be required to include OID in income as it accrues, prior to the receipt of cash attributable to such income. U.S. holders, however, would be entitled to claim a loss upon maturity or other disposition of such notes with respect to interest amounts accrued and included in gross income for which cash is not received. Such a loss generally would be a capital loss. A holder of a Series 2004-B (Taxable) Bond that purchases a Series 2004-B (Taxable) Bond for less than its adjusted issue price (generally its accreted value) will have purchased such Series 2004-B (Taxable) Bond with market discount. If such difference is not considered to be de minimis, then such discount ultimately will constitute ordinary income (and not capital gain). Further, absent an election to accrue market discount currently, upon a sale or exchange of a Series 2004-B (Taxable) Bond, a portion of any gain will be ordinary income to the extent it represents the amount of any such market discount that was accrued through the date of sale. In addition, absent an election to accrue market discount currently, the portion of any interest expense incurred or continued to carry a market discount bond that does not exceed the accrued market discount for any taxable year will be deferred. A holder of a Series 2004-B (Taxable) Bond that has an allocated basis in the Series 2004-B (Taxable) Bond that is greater than its adjusted issue price (generally its accreted value), but that is less than or equal to its principal amount, will be considered to have purchased the Series 2004-B (Taxable) Bond with acquisition premium. The amount of OID that such holder of a Series 2004-B (Taxable) Bond must include in gross income with respect to such Series 2004-B (Taxable) Bonds will be reduced in proportion that such excess bears to the OID remaining to be accrued as of the acquisition of the Series 2004-B (Taxable) Bond. A holder of a Series 2004-B (Taxable) Bond may have a basis in its pro rata share of the Series 2004-B (Taxable) Bonds that is greater than the principal amount of such Series 2004-B (Taxable) Bonds. Holders of Series 2004-B (Taxable) Bonds should consult their own tax advisors with respect to whether or not they should elect to amortize such premium, if any, with respect to such Series 2004-B (Taxable) Bonds under section 171 of the 1986 Code.

Sale and Exchange of Series 2004-B (Taxable) Bonds. Upon a sale or exchange of a Series 2004-B (Taxable) Bond, a holder generally will recognize gain or loss on the Series 2004-B (Taxable) Bonds equal to the difference between the amount realized on the sale and its adjusted tax basis in such Series 2004-B (Taxable) Bond. Such gain or loss generally will be capital gain (although any gain attributable to accrued market discount of the Series 2004-B (Taxable) Bond not yet taken into income will be ordinary). The adjusted basis of the holder in a Series 2004-B (Taxable) Bond will (in general) equal its original purchase price increased by any accrued OID (other than OID reduced due to acquisition premium) and decreased by any principal payments received on the Series 2004-B (Taxable) Bond. In general, if the Series 2004-B (Taxable) Bond is held for longer than one year, any gain or loss would be long term capital gain or loss, and capital losses are subject to certain limitations.

Foreign Investors. Distributions on the Series 2004-B (Taxable) Bonds to a non-U.S. holder that has no connection with the United States other than holding its Series 2004-B (Taxable) Bonds generally will be made free of withholding tax, as long as that the holder has complied with certain tax identification and certification requirements.

RATINGS

Standard & Poor's, Moody's and Fitch have assigned the 2004 Bonds the ratings of AA-, Aaa and AA-, respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the 2004 Bonds. Such ratings reflect only the respective views of such rating agencies, and an explanation of the significance of such ratings may be obtained only from the rating agency furnishing the same. There is no assurance that any or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the 2004 Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2004 Bonds from Energy Northwest and to make a bona fide public offering of such Bonds at not in excess of the public offering prices set forth on the inside cover of this Official Statement. Aggregate underwriters' compensation and discount under the bond purchase contract is $2,944,629.27. The Underwriters' obligations are subject to certain conditions precedent contained in the bond purchase contract and they will be obligated to purchase all of the 2004 Bonds if any such 2004 Bonds are purchased. The 2004 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2004 Bonds into investment trusts) at prices lower than such initial offering prices and such initial offering prices may be changed from time to time by the Underwriters of the 2004 Bonds.

CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934 ("Rule 15c2-12"), Energy Northwest and Bonneville will enter into Continuing Disclosure Agreements, to be dated the date of delivery of the 2004 Bonds, for the benefit of holders of the 2004 Bonds, to provide certain financial information and operating data relating to Energy Northwest (the "Energy Northwest Annual Information"), certain financial information and operating data relating to Bonneville (the "Bonneville Annual Information" and, together with Energy Northwest Annual Information, the "Annual Information") and to provide notices of the occurrence of certain enumerated events with respect to the 2004 Bonds, if material. Energy Northwest

Annual Information is to be provided not later than December 31 of each year, commencing December 31, 2004. The Bonneville Annual Information is to be provided not later than March 31 of each year, commencing March 31, 2005. The Annual Information will be filed with each Nationally Recognized Municipal Securities Information Repository (the "NRMSIRs") and with the State Depository for the State of Washington, if such State Depository exists (the "State Depository"). At this time, there is no State Depository. Notices of aforesaid enumerated events will be filed by Energy Northwest with the NRMSIRs or the Municipal Securities Rulemaking Board (the "MSRB") and with the State Depository. Energy Northwest and Bonneville have complied with all previous undertakings with respect to Rule 15c2-12. The nature of the information to be provided in the Annual Information and the notices of such material events is set forth in Appendix J — "SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS."

INITIATIVE AND REFERENDUM

Under the State Constitution, the voters of the State have the ability to initiate legislation and modify existing legislation through the powers of initiative and referendum, respectively. The initiative power in Washington may not be used to amend the State Constitution. Initiatives and referenda are submitted to the voters upon receipt of a petition signed by at least 8% (initiative) and 4% (referenda) of the number of voters registered and voting for the office of Governor at the preceding regular gubernatorial election. Any law approved in this manner by a majority of the voters may not be amended or repealed by the Legislature within a period of two years following enactment, except by a vote of two-thirds of all the members elected to each house of the Legislature. After two years, the law is subject to amendment or repeal by the Legislature in the same manner as other laws. Any such initiatives or referenda could affect the laws governing Energy Northwest.

MISCELLANEOUS

The references, excerpts and summaries contained herein of the Prior Lien Resolutions, Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements, the Post Termination Agreements and any other documents or agreements referred to herein do not purport to be complete statements of the provisions of such documents or agreements and reference should be made to such documents or agreements for a full and complete statement of all matters relating to the 2004 Bonds, the basic agreements securing the 2004 Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Prior Lien Resolutions, Electric Revenue Bond Resolutions, Net Billing Agreements, the Columbia Project Agreement, Assignment Agreements and the Post Termination Agreements and other reports, documents, agreements and studies referred to herein and in the Appendices hereto are available upon request at the office of Energy Northwest in Richland, Washington.

The authorizations, agreements and covenants of Energy Northwest are set forth in the Prior Lien Resolutions and Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the 2004 Bonds is to be construed as a contract with the holders of such Series of 2004 Bonds. Any statements made in this Official Statement involving matters of opinion or estimates, whether or not expressly so identified, are intended merely as such and not as representations of fact.

Bonneville has furnished the information herein relating to it.

ENERGY NORTHWEST

By: /s/ Edward E. Coates
Chairman, Executive Board

By: : /s/ Richard A. Bresnahan
Authorized Officer

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest (the "Issuer") by Bonneville for use in the Official Statement furnished by the Issuer with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2004-A; Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A; Project 3 Electric Revenue Refunding Bonds, Series 2004-A; Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable); Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2004-B (Taxable); Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable); and Columbia Generating Station Electric Revenue Bonds, Series 2004-C (collectively, the Series 2004 Bonds) (the "Official Statement"). Such information is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2004 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, is true and correct and does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this section and elsewhere in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

GENERAL

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

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

Bonneville's primary customer service area is the Pacific Northwest. Bonneville estimates that the population of the 300,000 square-mile service area is approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville markets the majority of this power to over 100 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service Bonneville provides to DSIs has diminished substantially relative to 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 2003 payment responsibility to the United States Treasury of $1.057 billion (including $315 million in principal payments in advance of due dates under the Debt Optimization Proposal as described in this Appendix A) in full and on time. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Proposal."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments relating to Net Billed 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 other cash payments of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

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

For much of its history, Bonneville had a high degree of certainty that its revenues from power and transmission services would be sufficient to recover all of its costs without concern for substantial price competition from other suppliers. In the mid-1990's, competition increased in the wholesale electricity industry. Bonneville was particularly affected because its business, both power marketing and the provision of bulk transmission, is primarily wholesale. This increase in competition was due to a number of factors, including electric power deregulation advanced under the National Energy Policy Act of 1992 ("EPA-1992"). As a result of deregulation actions relating to Western energy markets, hydroelectric generating conditions primarily relating to the amount of precipitation in the West, natural gas prices, variations in load levels due to changes in economic activity and the weather, and a variety of other factors, wholesale power prices in the West have been very volatile in the past several years. Prices peaked in the fiscal year 2000-2001 period at levels that were many multiples of historical prices but declined in fiscal year 2002. Prices have since risen somewhat in fiscal year 2003 and 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, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments

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

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

In view of the foregoing Augmentation Purchases and load reduction agreements, lowered expectations regarding Regional load growth, and declining expectations that aluminum company DSIs will meet their power purchase obligations, Bonneville now believes that its firm resources, including existing Augmentation Purchases, could exceed its expected firm load obligations in fiscal years 2004 through 2006. Bonneville therefore believes that it will not have to make substantial additional Augmentation Purchases to meet its Subscription loads through at least fiscal year 2006, subject to changes in contracted loads or anticipated generation from Federal System generating resources, and subject to the receipt of power under existing Augmentation Purchases and other power purchase and related agreements. While the foregoing circumstances now mean that in general Bonneville expects to have little need to acquire additional power to meet loads, Bonneville may have a relatively modest amount of firm power in excess of actual firm loads through fiscal year 2006 and may have some market price risk in making discretionary power sales of that excess firm power.

In fiscal years 2000-2001, coincident with the development of the power sales and related contracts under the Subscription Strategy, Bonneville developed and proposed power rates for such Subscription agreements for the five-year period beginning October 1, 2001 (the "2002 Final Power Rates"). The 2002 Final Power Rates are comprised of "base rates" and certain rate level adjustment mechanisms. FERC approved the proposed 2002 Final Power Rates, including the base rates and the rate level adjustment mechanisms, on July 21, 2003. FERC's review and confirmation of the 2002 Final Power Rates are subject to legal challenge in the Ninth Circuit Court and a number of customers have challenged approval of the 2002 Final Power Rates in that court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

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

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

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

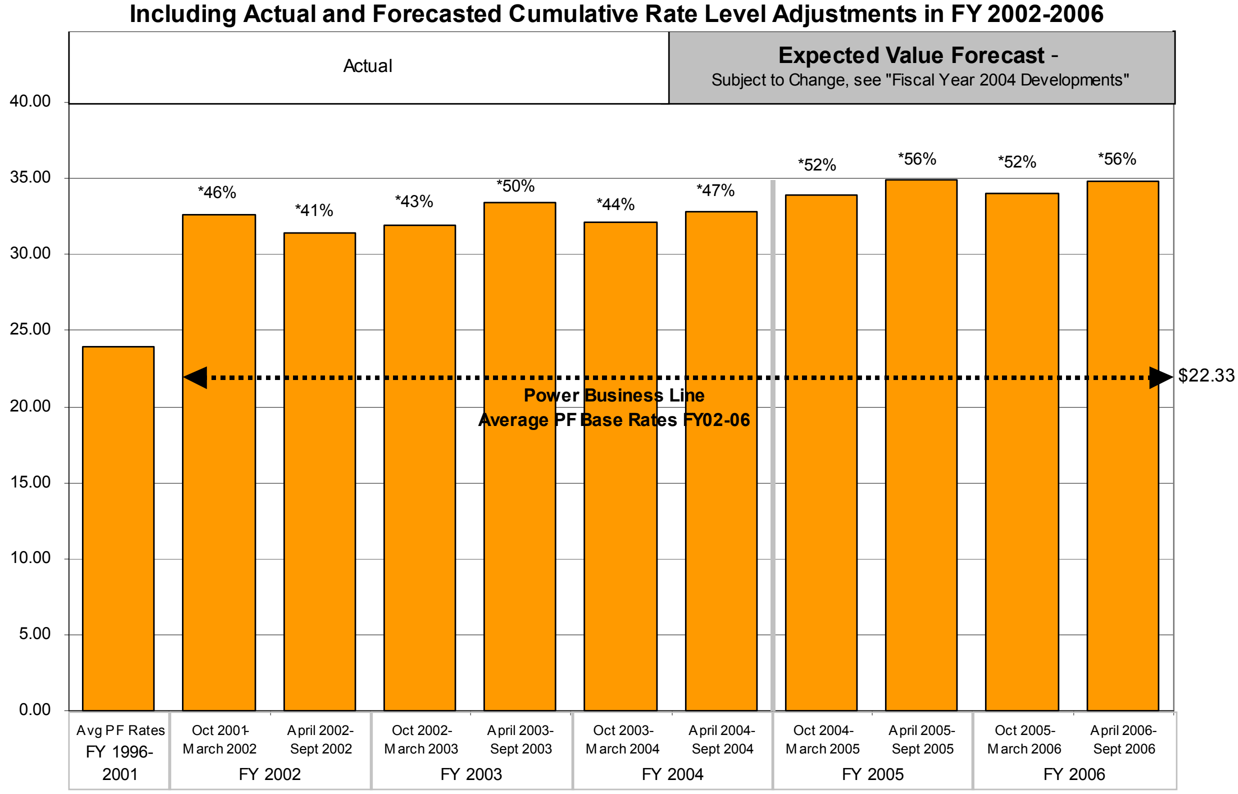
Under the third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause ("SN-CRAC"), Bonneville may impose one or more separate rate level increases in order to recover costs on a temporary basis if certain conditions indicating that Bonneville is not adequately recovering its costs are met. In early calendar year 2003, Bonneville determined that the conditions triggering an SN-CRAC proceeding had been met and later developed and formally proposed a specific SN-CRAC rate level adjustment to be effective for fiscal years 2004 through 2006. FERC approved the SN-CRAC rate level adjustment on May 10, 2004. FERC's approval of the SN-CRAC rate level adjustment is subject to review in Federal appellate court and Bonneville expects that litigation will be filed challenging the SN-CRAC rate level adjustment and FERC's approval thereof.

The SN-CRAC rate level adjustment for each of fiscal years 2004 through 2006 is to be made on the basis of the Power Business Line's third quarter projected net revenues for the respective prior fiscal year. Certain costs in a number of major cost categories would be capped and are not automatically recovered through the final proposed SN-CRAC rate level adjustment. The maximum revenue recoverable through the proposed SN-CRAC rate level adjustment in fiscal years 2004-2006 is capped at $320 million per year. In addition, Bonneville will provide a refund to customers from previously collected revenue if Bonneville's Power Business Line accumulated net revenues exceed established threshold levels.

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

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

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



*Each bar represents the average full requirements rate for the indicated period, taking into account the LB-CRAC, FB-CRAC and SN-CRAC. The percentage presented above each bar is the adjusted rate over Base Rates taking into account the LB-CRAC, SN-CRAC and FB-CRAC. The forecasted rates reflect Bonneville forecasts as of August 28, 2003.

In developing the SN-CRAC rate level adjustment proposal, Bonneville estimated that it would provide Bonneville with an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time over the three fiscal years beginning October 1, 2003. Such estimates were based on a number of forecasts and assumptions, which may not be realized. Notwithstanding the SN-CRAC rate level adjustment approved by FERC, Bonneville has reserved the ability to develop an additional SN-CRAC rate level adjustment mechanism during the five-year rate period. Whether and the extent to which Bonneville would increase rate levels under an additional SN-CRAC adjustment would be determined in view of all facts and circumstances at the time.

Several of Bonneville's customers and customer groups have filed separate suits in the Ninth Circuit Court challenging Bonneville's decision to initiate the 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 provisions of the 2002 Final Power Rates have been met. The petitioners have not sought expedited review by or injunctive relief from the court in this matter. As noted above, a number of customers have entered a legal challenge to FERC's approval of the 2002 Final Power Rates Proposal.

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 2004-2006 will be at or near average market prices for such period based on similar power products. Bonneville believes that its Subscription power rates will not exceed the cost of new natural gas fired generation when shaped to serve load similar to the shaping ability of the Federal System. Such belief is based on market, rate and other forecasts that are subject to many variables most of which are not within Bonneville's control.

For a more detailed description of Bonneville's proposal for power rates applicable to Subscription power sales, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates."

Bonneville's Fiscal Year 2003 Financial Results

According to final audited results for the fiscal year ended September 30, 2003 ("Fiscal Year 2003"), Bonneville made payments to the United States Treasury of $1.057 billion, which included full and timely payments of Bonneville's scheduled repayment responsibilities and $315 million in advance amortization of debt under the Debt Optimization Proposal. For a description of the Debt Optimization Proposal see "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Proposal." Bonneville also recorded positive net revenues of approximately $555 million, although absent the net revenue effects of the Debt Optimization Proposal and other debt management actions relating to Energy Northwest, Bonneville had net revenues of $37 million. The $37 million in fiscal year end net revenues also exclude $55 million in positive non-cash, mark-to-market accounting adjustments under the Financial Accounting Standards Board Statement of Accounting Standard No. 133. In addition, Bonneville had $511 million in fiscal year end financial reserves. Of that $511 million, approximately $233 million were attributable to actions taken throughout the fiscal year to assure financial liquidity. These actions deferred payments into the future, creating future cash obligations and delaying cash disbursements. By way of contrast, in fiscal year 2002, Bonneville made payments to the United States Treasury in the amount of $1.056 billion (including $266 million in advance amortization of debt under the Debt Optimization Proposal) and recorded net revenues of about $9.5 million. However, Bonneville recorded a net operating loss of about $348 million after excluding the positive net revenue effects of the Debt Optimization Proposal and other Energy Northwest debt management actions. In addition, Bonneville closed fiscal year 2002 with financial reserves in the amount of approximately $188 million.

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.

A number of elements contributed to Bonneville's financial performance in fiscal year 2003. First, with indications in early calendar year 2002 that revenues from discretionary power sales in such year would be lower than previously forecasted, Bonneville began reducing its costs substantially. Bonneville continued to do so in fiscal year 2003. Through expense reductions, deferrals and other actions, Bonneville reduced costs in fiscal year 2003 by about $200 million, and expects that the cost reduction program will improve its Power Business Line financial condition by $350 million in aggregate over the fiscal year 2003-2006 period. Bonneville continues to explore additional cost reductions and deferrals.

Second, in fiscal year 2003 Bonneville received a total of about $175 million of United States Treasury repayment credits, most of which are derived under section 4(h)(10)(C) of the Northwest Power Act. These credits are provided to reimburse Bonneville for certain fish and wildlife costs incurred by Bonneville, including power purchases made by Bonneville that are attributable to the effects of operating the hydroelectric system for the benefit of fish. Bonneville's United States Treasury repayment credits for fiscal year 2003 included about $79 million from the Fish Cost Contingency Fund, which represented credits available to Bonneville for fish and wildlife costs on behalf of non-power uses of the federal dams in years prior to fiscal year 1995. Of the remaining fish and wildlife credits in the amount of approximately $97 million, virtually all were provided for applicable fish and wildlife costs borne by Bonneville in fiscal year 2003. 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."

Third, Bonneville triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2003. This rate level adjustment allowed 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 in this Appendix A. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001." The FB-CRAC had 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. 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 rates for the second six months of the fiscal year.

Fourth, after taking into account the effects of the various rate level adjustments under the Final 2002 Power Rate Proposal, as described in this Appendix A, Bonneville's affected Subscription Power rates in fiscal year 2003 remained at levels comparable to those in effect in fiscal year 2002.

Fifth, despite water conditions in the Pacific Northwest that were 85 percent of average, Bonneville's revenues from discretionary power sales increased because of higher market prices for such power.

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

Fiscal Year 2004 Developments

Bonneville's Unaudited Fiscal Year 2004 Second Quarter Results and Fiscal Year-End Forecast as of March 31, 2004.

Compared to the first six months of fiscal year 2003, Bonneville's Unaudited Fiscal Year 2004 Second Quarter Results as of March 31, 2004 indicate that Bonneville's total operating expenses decreased by approximately $329 million (or roughly 23 percent) in the first six months of fiscal year 2004, primarily because of decreased operations and maintenance expense and decreased purchased power expense. In addition, revenues from electricity sales and transmission declined by $198 million (or roughly 12 percent), compared to the first six months of fiscal year 2003, primarily as a result of lower secondary power revenues, about $100 million of which was causedby lower than average water. The total operating expenses and revenues from electricity sales also reflect recent accounting guidance from the Emerging Issues Task Force (EITF) of the Financial Accounting Systems Board. Under this new guidance (referred to herein as "Emerging Issues Task Force Issue No. 03-11"), which is applicable to Bonneville as of the quarter ending March 31 2004, both revenues and expenses associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) are to be reported on a "net" basis in both operating revenues and purchased power expense. Formerly, such bookouts were to be treated on a "gross" basis. Application of the new guidance thus decreased both operating revenues and purchase power expense for the first six months of fiscal year 2004 by $98 million and has no effect on net revenue, cash flows or margins. Absent application of the new guidance, total operating expenses in the first six months of fiscal year 2004 would have decreased by $231 million, and revenues from electricity sales and transmission would have decreased by $100 million, in each case when compared to the first six months of fiscal year 2003. Prospective application of Emerging Issues Task Force Issue No. 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts when compared financial statements issued prior to the application of the guidance.

Bonneville's cash balance at the end of the fiscal year 2004 second quarter was $865.5 million, compared with $372.9 million as of the same time in fiscal year 2003. For further detail see, Appendix B-2 –"FEDERAL SYSTEM UNAUDITED FINANCIAL STATEMENTS FOR THE SIX MONTHS ENDED MARCH 31, 2004" in the Official Statement.

In addition, based on various expectations and assumptions, Bonneville's second quarter review indicates that Bonneville has a very high degree of certainty that it will make its planned fiscal year 2004 annual United States Treasury payments in full and on time. These planned payments include planned early amortization of about $346 million principal amount of United States Treasury repayment obligations under the Debt Optimization Proposal, described herein. Among the factors contributing to this expectation are the comparatively high level of reserves currently in the Bonneville Fund, the continuing effects of the various cost recovery adjustment rate mechanisms described herein, low exposure to purchased power expense to meet committed loads, and lowered interest expense and operating expenses.

Snowpack and other measures of precipitation conditions in the Region are below average for this time of year and forecasts prepared outside of but relied on by Bonneville indicate that overall hydroelectric generation will be below average in fiscal year 2004. Fiscal year 2004 water conditions are currently forecast to be about 25-26 percent below average and are expected to result in lower revenues from discretionary power sales in fiscal year 2004 than Bonneville forecasted in developing the SN-CRAC rate level adjustment. Nonetheless, Bonneville expects that even without taking into account the positive cash flow effects to Bonneville in fiscal year 2004 associated with the reduction in the Energy Northwest-approved fiscal year 2005 budget, its end-of-fiscal-year financial reserves (after making scheduled payments to the United States Treasury, including planned early amortization of United States Treasury repayment obligations under the Debt Optimization Proposal) will be about equal to the target of $447 million for the end of fiscal year 2004 used by Bonneville in developing the SN-CRAC rate level adjustment. The primary reasons for relatively little change in fiscal year end reserve forecasts despite low water conditions and lower discretionary power sales revenues are (i) an increase in cash inflows to Bonneville at the end of fiscal year 2004 because net billing of Energy Northwest's fiscal year 2005 costs is expected to be fulfilled very early in Energy Northwest's fiscal year , and (ii) about $50 million in reductions in operating expenses of Bonneville in its fiscal year 2004.

The foregoing expectations and forecasts are subject to many variables and assumptions and therefore may not be realized.

With respect to power rate levels for fiscal year 2005, Bonneville is scheduled to set the SN-CRAC rate level for fiscal year 2005 in August of 2004. The decision on the level of the SN-CRAC adjustment will be based on then-current information. Numerous considerations could affect the SN-CRAC rate level adjustment applicable in fiscal year 2005, including, but not limited to, projected end-of-fiscal-year 2004 financial reserves, analyses of the probability that Bonneville will meet its United States Treasury payments in fiscal year 2005, the projected financial effects in fiscal year 2005 of the current below average water conditions, and the impact of an SN-CRAC adjustment on overall power rate levels. Among other factors that could affect overall power rate levels are the possible favorable financial effects under proposed agreements between Bonneville and certain

Regional IOUs that would alter terms of their Residential Exchange Settlement Agreements, and the possible improvements to hydroelectric power generation from changes in dam operations now under consideration by Bonneville, the Corps and the Bureau. In view of these and other uncertainties, Bonneville is unable to predict overall power rate levels for fiscal year 2005. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Residential Exchange Program Obligations," and "BONNEVILLE LITIGATION—Spill Reduction Litigation" herein.

Within Fiscal Year Prepayments of Appropriations Repayment Obligations.

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

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

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

In the second quarter of fiscal year 2004, Bonneville prepaid by about eight months approximately $73 million principal amount of appropriations repayment obligations that were due at the end of this fiscal year. Prior to making the above mentioned prepayment, Bonneville concluded that it had in excess of a 99 percent probability of making its full scheduled fiscal year 2004 payments to the United States Treasury and a slightly greater probability of making the subject appropriations repayment obligations in full in fiscal year 2004, after taking into account the interest savings to be achieved through early payment.

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

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

Power Marketing After Fiscal Year 2006

Bonneville currently estimates that its contracted-for loads and resources are in rough balance from fiscal year 2004 through fiscal year 2006, with Bonneville's having a relatively modest surplus of power under critical water assumptions.

After fiscal year 2006, however, Bonneville faces some uncertainty with regard to the amount of power loads Bonneville will be required to meet and hence the amount of power it may have to obtain in addition to existing Federal System generating resources. Bonneville currently has about 1000 average megawatts of Augmentation Purchases, which will decline to about 800 average megawatts by fiscal year 2006 before expiring at or near the end of fiscal year 2006. In addition, all of the remaining contractually-committed take or pay power purchases by aluminum company DSIs (originally in the amount of 1500 average megawatts although Bonneville is currently selling only about 200-300 average megawatts to such DSIs) will expire at the end of fiscal year 2006. Moreover, in developing the Subscription Strategy in calendar years 1999-2001, Bonneville assumed that it would meet through physical power sales about 2200 average megawatts of Regional IOU residential and small farm loads after fiscal year 2006 under the Regional IOU Exchange Settlements. Under those Settlements, Bonneville has reserved the unilateral right to determine how much of its Regional IOU Exchange Settlement obligation will be met through physical sales of power to Regional IOUs versus the payment of monetary benefits to Regional IOUs. Finally, while a large portion of the existing Regional Preference Customer Subscription power sales remain in effect through fiscal year 2011, about 800 average megawatts of such loads are under contract only through fiscal year 2006. Bonneville's Final 2002 Power Rates will expire at the end of fiscal year 2006. Rate levels in the period after fiscal year 2006 will affect the inclination that such customers may have to increase or decrease the amount of loads they place on Bonneville.

Under critical water assumptions, Bonneville currently estimates that if (i) Bonneville were to have no physical power sales to aluminum company DSIs or to Regional IOUs under the Regional IOU Exchange Settlement after 2006, (ii) existing, long-term, non-Subscription power sales and similar arrangements remain in effect, (iii) existing power sales to Regional Preference customers remain in effect, with forecasted load growth under partial and full requirements contracts, and (iv) current forecasts of the output of Federal System generating resources are realized, Bonneville may have a small firm power deficit of less than 100 average megawatts in fiscal years 2007 and 2008, increasing, roughly, to about 240 average megawatts in fiscal year 2009, 185 average megawatts in fiscal year 2010 and 320 average megawatts in fiscal year 2011. Bonneville views these possible deficits as relatively modest in view of the Federal System's firm power capability of in excess of 8000 average megawatts under critical water assumptions. However, if Bonneville were to enter into physical power sales obligations to Regional IOUs to effect the Regional IOU Exchange Settlements and/or to DSIs or others, without corresponding reductions in power sales to Regional Preference Customers, Bonneville could have larger generating resource deficits. This could increase the amount of power purchases that Bonneville would otherwise have to make, perhaps substantially.

In view of the uncertainties surrounding the period after fiscal year 2006, in calendar year 2002, Bonneville and its customers initiated a Regional discussion ("Regional Dialogue"). The Regional Dialogue seeks to address Bonneville's role in meeting Regional electric power loads in the future. In the context of the Regional Dialogue, Bonneville has indicated to Regional customers its concerns that it not be placed in the position of attempting to acquire a substantial portion of the Region's power needs, as occurred in calendar year 2001 during the West Coast energy crisis.

In a letter dated December 9, 2003, to the Pacific Northwest Electric Power and Conservation Planning Council (the "Council"), an entity established by Congress to guide electric power planning in the Region, Bonneville reiterated that one of Bonneville's goals is to provide stable, low-cost power rates and benefits to the Region after fiscal year 2006. For a discussion of the Council, see "POWER BUSINESS LINE—Bonneville's Authority to Add Resources" and "—Fish and Wildlife" in this Appendix A. Bonneville stated that it would prefer to achieve these objectives by limiting the incremental load obligations Bonneville would bear above existing Federal System generating resources. As a means of balancing its statutory obligation to meet loads placed on it by Preference and Regional IOU customers with the goal of low, stable power rates, Bonneville indicated to the Council that Bonneville would prefer to have customers in the Region assume the role of meeting incremental power needs. Bonneville also stated that it viewed positively a Council proposal to limit the amount of firm power sales Bonneville makes at embedded cost rates to roughly the output of the existing Federal System. Bonneville also stated that a "tiered rate" design for the Subscription power sales in the period after 2006 would be a means of achieving this end. Under tiered rates, costs of new power purchases above the existing Federal System generating resources would not be melded with the comparatively low embedded costs of Federal System resources. Rather, the costs of the new power purchases would be separately recovered under an additional power rate or rate mechanism. To the extent a customer's purchases from Bonneville would be allocated for recovery under such a rate or rate mechanism, then the customer would bear the costs of the related incremental power purchases.

The ultimate load obligations that Bonneville will assume will depend on a number of factors, including the outcome of the Regional Dialogue, and hence are uncertain. Bonneville does not anticipate finally resolving its load obligations in the post-fiscal year 2006 period until at least fiscal year 2005.

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 2004."

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

Bonneville defines "firm power" as electric power that (i) is continuously available from the Federal System even during the most adverse water conditions, and (ii) is useful for meeting Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e.*, the worst low-water period on record for the Columbia River Basin. Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity and firm energy. Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2004, the Federal System, including firm energy purchases, would be capable of producing about 9,926 average megawatts of firm energy under certain assumptions of low water conditions. In conducting loads and resources evaluations Bonneville utilizes the term "operating year," meaning the twelve calendar months beginning each August 1. See the following table "Operating Federal System Projects For Operating Year 2004."

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.

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

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

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

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

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table 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 2004

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 2004, 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 2004[1]

Project	Initial Year in Service	No. of Generating Units	January Capacity (Peak MW)[2]	Maximum Energy (aMW)[3]	Median Energy (aMW)[4]	Firm Energy (aMW)[5]
United States Bureau of Reclamation Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	5,748	3,110	2,433	1,929
Hungry Horse	1952	4	281	126	101	77
Other Bureau Projects[6]		16	225	163	156	130
1. Total USBR Projects		53	6,254	3,399	2,690	2,136
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,155	1,660	1,338	1,061
John Day	1968	16	2,037	1,479	1,108	802
The Dalles including Fishway[7]	1957	24	1,752	1,068	822	594
Bonneville including Fishway	1938	20	839	594	540	362
McNary	1953	14	947	734	690	518
Lower Granite	1975	6	690	459	345	221
Lower Monumental	1969	6	677	449	315	223
Little Goose	1970	6	734	453	334	218
Ice Harbor	1961	6	540	361	246	138
Libby	1975	5	549	300	220	167
Dworshak	1974	3	422	233	188	126
Other Corps Projects[8]		20	398	295	269	225
2. Total USACE Projects		153	11,740	8,095	6,415	4,655
3. Total USBR and USACE Projects (line 1 + line 2)		**206**	**17,994**	**11,494**	**9,105**	**6,791**
Non-Federally-Owned Projects						
Columbia Generating Station	1984	1	1,150	1,000	1,000	1,000
Other Non-Federal Hydro Projects[9]		5	32	59	47	45
Other Non-Federal Projects[10]		13	65	121	121	121
4. Total Non-Federally-Owned Projects		**19**	**1,247**	**1,180**	**1,168**	**1,166**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases[11]		**n/a**	**1,844**	**1,969**	**1,969**	**1,969**
Total Federal System Resources **6. Total Federal System Resources (line 3 + line 4 + line 5)**		**225**	**21,085**	**14,643**	**12,242**	**9,926**

Source: 2002 Pacific Northwest Loads and Resources Study, Bonneville, December 2002.

(1) Operating Year 2004 is August 1, 2003 through July 31, 2004.

(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 hydro-regulation 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), Green Springs (1960), Minidoka (1909), Black Canyon (1925) and Roza (1958).

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

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

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

(10) Other Non-Federal Projects include the following projects: 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 2 (1999), Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing and Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, 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.

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

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

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

Preference Customers

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

Direct Service Industrial Customers

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

Regional Investor-Owned Utilities

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

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

Exports of Surplus Power to the Pacific Southwest

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

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

In 1995, in view of the Regional load diversification away from Bonneville that was then occurring, Congress enacted a law that authorizes Bonneville to sell for export out of the Region a limited amount of power unencumbered by the Regional Preference recall rights. Bonneville entered into a number of such excess federal power contracts that have remaining terms requiring Bonneville to export power 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.

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

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

Effect on Bonneville of Developments In California Power Markets

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

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

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 $84 million. Based on its current evaluation, Bonneville recorded provisions for uncollectible amounts, which in management's best estimate are sufficient to cover any potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

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

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

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

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

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

While Bonneville was a participant in the two foregoing refund proceedings, Bonneville took the position before FERC in certain petitions for rehearing that 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 non-jurisdictional utilities' petitions. Several non-jurisdictional utilities, including Bonneville, have filed appeals in Federal appellate court.

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

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

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 requirements 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 helped define Bonneville's power-marketing program for the ten years beginning October 1, 2001 and intended 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. For a description of loads and resources see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE FINANCIAL CONDITION."

Bonneville's Authority to Add Resources. In order to meet the foregoing power sales obligations, Bonneville may have to obtain electric power from sources in addition to the existing Federal System hydroelectric projects and existing non-Federally owned generating projects, the output of which Bonneville has acquired by contract. By law, Bonneville may not own or construct generating facilities. However, the Northwest Power Act authorizes Bonneville to acquire resources to serve firm loads pursuant to certain procedures and standards set forth in the Northwest Power Act. "Resources" are defined in the Northwest Power Act to mean: (1) electric power, including the actual or planned electric power capability of generating facilities; or (2) the actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from conservation measures. "Conservation" is defined in the Northwest Power Act to mean measures to reduce electric power consumption as a result of increased efficiency of energy use, production or distribution.

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

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

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

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

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

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

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

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

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

As a second short-term resource strategy, Bonneville encourages electric power conservation measures. Bonneville provides a 0.5 mills per kilowatt-hour rate discount to those of its customers that implement conservation measures and/or renewable resource projects. In addition, Bonneville is purchasing about 100 average megawatts of electric power conservation through fiscal year 2006 as part of its conservation-augmentation strategy. Any such resource development should lessen Bonneville's reliance on spot market power purchases.

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

Under the Subscription Strategy, Bonneville substantially increased its contracted load obligation, which led Bonneville to make Augmentation Purchases. Consistent with the foregoing resource strategy, Bonneville is relying 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 its 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 decline 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. Bonneville's settlement of its Residential Exchange obligations was later challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Fish and Wildlife

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

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

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

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

Bonneville; and, (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for the Lower Snake River Hatcheries and of the Corps and Bureau for Federal System projects.

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

Bonneville estimates that in aggregate, Direct Costs and Replacement Power Purchase Costs were about $439.6 million in fiscal year 2003. In addition, Bonneville estimates that it had about $79.2 million in Foregone Power Revenues.

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

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

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

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

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

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

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

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 Rates were several that would have called for breaching four Federal System Snake River dams. The direct cost of breaching the dams would be very high. In addition, the loss of the generation from the dams would substantially affect the power generation capability of the Federal System, reducing current expected output by approximately 1200 average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales. 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. The 2000 Biological Opinion includes provisions for NOAA Fisheries to issue evaluations near the end of each of calendar years 2003, 2005 and 2008, 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 evaluations are required to grade 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. In December 2003, NOAA responded to the 2003 checkpoint with a "between failing and acceptable" rating. Under the 2000 Biological Opinion, NOAA Fisheries indicated 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 until June 2004 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. In an additional ruling in late June 2003, the court agreed to permit the 2000 Biological Opinion to remain in effect on an interim basis for up to one year while the 2000 Biological Opinion is on remand to NOAA Fisheries. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

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

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, leaving an unused balance of about $78 million in the Contingency Fund. The conditions governing access to the Contingency Fund were not met in fiscal year 2002 but poor water conditions in fiscal year 2003 provided access to the Contingency Fund and Bonneville applied the remaining credits in the fund to its United States Treasury payment in fiscal year 2003. Thus, the Contingency Fund is fully and finally depleted.

Council's Fish and Wildlife Program. In November 2002, the Council adopted a new Fish and Wildlife Program (the "2002 Program"). The 2002 Program focuses on an ecosystem approach to rebuilding fish and wildlife populations in the Columbia River Basin, consistent with the 2000 Biological Opinion. Estimated costs to Bonneville of the Council's measures, as then encompassed in amendments to the Council's 1995 Program, were included in Bonneville's assumptions for the 2002 Final Power Rates. The 2002 Program, like the Council's predecessor program, sets forth an "integrated program" budget to Bonneville for both the Council Fish and Wildlife Program and the off-site mitigation program under the 2000 Biological Opinion. The costs of the integrated program ("Integrated Program Costs") are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General."

In response to financial developments over the past two years, Bonneville reiterated, and the Council confirmed, an average expense accrual budget level of $139 million per year for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's 2002 Program for fiscal years 2003 through 2006. This level is in the range of projected costs assumed in Bonneville's 2002 Final Power Rates. In June 2003, the Yakama Nation, a tribal entity, filed a petition in the Ninth Circuit Court to request a review of Bonneville's fund levels under the Council's 2002 Program, as well as the Council's support of such funding levels. See "BONNEVILLE LITIGATION—Yakama Nation Litigation."

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

Power Marketing in the Period After Fiscal Year 2001

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

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

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

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

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

The Slice of the System (or "Slice") contracts require that customers make monthly payments based on 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 to conduct an audit and prepare a final report, which was completed on June 13, 2003. The Slice customer audit asserted that the Slice customers' payments for fiscal year 2002 should be adjusted by removing an additional $83 million from Bonneville's charges. Under the Slice contracts, Bonneville and the Slice customers have 60 days to resolve any outstanding issues after the final report is concluded, after which time Bonneville's response to the auditor's report becomes a final action for purposes of judicial review under the Northwest Power Act. In a related action, several Slice customers filed litigation requesting review of Bonneville's accounting with regard to the Slice of the System product charges for fiscal year 2002. See "BONNEVILLE LITIGATION—Slice Litigation."

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

Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of contract amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2002. These amendments and arrangements increased the amount of cash payments that Bonneville would make in respect of the Residential Exchange Settlement Agreements and reduced the amount of physical power sales thereunder. As result, the aggregate cash payments to Regional IOUs that Bonneville has made related to the Residential Exchange Settlement Agreements were about $355 million in fiscal year 2002 and $327 million in fiscal year 2003 and, under a variety of assumptions, are projected to be $389 million in fiscal year 2004, $468 million in fiscal year 2005, and $447 million in fiscal year 2006. As a result of the foregoing load reductions, Bonneville reduced its obligation to make physical power sales under the Residential Exchange Settlement Agreements to about 258 average megawatts of power from fiscal year 2002 through fiscal year 2006. This remaining Residential Exchange Settlement Agreement power sale is to a single Regional IOU at the RL Rate, and is subject to the LB-CRAC, FB-CRAC and SN-CRAC rate level adjustments.

The aggregate cash payments to Regional IOUs described above can be broken down into three separate components. The first component reflects payments for Monetary Benefits under the original Residential Exchange Settlement Agreements. Bonneville estimates that it will pay about $132 million in Monetary Benefits per year on average over the five-year rate period. This amount was about $144 million in each of fiscal years 2002 and 2003. The second component reflects payments for load reductions arising from contract amendments. Through 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 $255 million per year in aggregate.

The two Regional IOUs (Puget and PacifiCorp) 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. (The litigation has not been settled.) The two Regional IOUs also agreed that Bonneville could defer making a portion of such payments until later years of the rate period. These payments, whether discounted or not, are recovered under the LB-CRAC in the 2002 Final Power Rates.

The third component reflects load reductions achieved by the exercise by three Regional IOUs of certain conversion rights in their Residential Exchange Settlement Agreements. Through the exercise of these rights, Bonneville's obligation to sell about 125 average megawatts of power was converted into obligations to provide cash payments of about $10 million per year in fiscal years 2002 and 2003. Such payments are affected by the operation of the LB-CRAC, FB-CRAC and SN-CRAC and are expected to fluctuate somewhat from year to year in the remaining three years of the rate period. The payments, whether discounted or not are not recovered under the LB-CRAC in the 2002 Final Power Rates.

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

In developing the Subscription process, Bonneville originally expected to meet its Residential Exchange Settlement Agreement obligations in the period after fiscal year 2006 in full through the actual provision of about 2200 average megawatts of electric power to the Regional IOUs. Under contract provisions with the Regional IOUs, Bonneville has the right to determine how much of its fiscal year 2007-2011 obligation under the Residential Exchange Settlement Agreements will be provided in the form of cash payments and how much will be provided in the form of actual power sales. 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. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

In April 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) proposed to enter into further agreements that would affect such IOUs' Residential Exchange Settlement Agreements. These additional agreements would have the effect of reducing by one half certain payments in the aggregate amount of $200 million that Bonneville would otherwise owe to the two subject Regional IOUs in fiscal years 2005 and 2006 under their Residential Exchange Settlement Agreements. In addition to the foregoing reduction in payments, Bonneville would also defer paying until fiscal years 2007-2011 the remaining $100 million aggregate amount (plus interest) otherwise owed by Bonneville to the two Regional IOUs in fiscal years 2005 and 2006. In return, the two Regional IOUs would obtain assurances from Bonneville as to the amount and nature of Residential Exchange Settlement benefits to be provided to them by Bonneville in fiscal years 2007-2011, as described below.

With respect to the other four Regional IOUs, Bonneville has tendered terms similar to those proposed for Puget and PacifiCorp, although the reduction in financial payments that Bonneville would make to such Regional IOUs in the current rate period would be only $3-$4 million in aggregate.

If Bonneville and all six of the Regional IOUs execute such agreements, Bonneville would provide and the Regional IOUs would receive only Monetary Benefits and not physical power under the Residential Exchange Settlement Agreements in fiscal years 2007-2011, thereby reducing Bonneville's load uncertainty by roughly 2200 average megawatts during those five fiscal years. The aggregate financial benefits paid by Bonneville in fiscal year 2007-2011 would have a floor of $100 million per fiscal year and a maximum of $300 million per fiscal year. In addition, Bonneville and the Regional IOUs would agree to an independent market price indicator for determining financial benefits in such period rather than using market price indicators developed by Bonneville in its power rate cases.

It is uncertain whether and when the foregoing agreements would be executed by the parties. Bonneville opened a public comment period on the proposed agreements that closed on May 14, 2004, and Bonneville expects that it would not sign any of the proposed agreements until the first week of June 2004. While all regulatory approvals needed by the Regional IOUs to execute their respective proposed agreements have been obtained, Bonneville also expects that none of the Regional IOUs would execute its respective proposed agreement until the late May or early June period.

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 Subscription program for the post-fiscal year 2001 period, Bonneville entered into five-year take-or-pay power sales contracts with a number of aluminum company DSIs under which agreements such DSIs agreed to purchase approximately 1500 average megawatts. 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's contracted sales obligations to aluminum company DSIs in fiscal year 2004 are about 600 average megawatts but Bonneville is currently delivering such DSIs about 200-300 average megawatts. The remainder of the sales to aluminum company DSIs (i) have been curtailed by contract amendment, (ii) were terminated because they were rejected in bankruptcy proceedings, or (iii) are not being performed by related DSIs pending likely rejection in bankruptcy proceedings. Currently, four aluminum company DSIs are under bankruptcy protection. See "BONNEVILLE LITIGATION—GNA Bankruptcy," "—Kaiser Aluminum Bankruptcy," and "—Longview Aluminum Bankruptcy."

In view of 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.

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 through fiscal year 2011 remains somewhat uncertain because, among other reasons, the Subscription contracts have provisions allowing customers to terminate such contracts if either FERC or the Ninth Circuit Court, which reviews FERC actions on Bonneville's rates, subsequently remands Bonneville's base power rates and Bonneville publishes a record of decision that adopts different rates for such period. The customers may not opt out of their contracts solely on the basis that Bonneville has included the cost recovery adjustment clauses in the rate proposal or that the cost recovery adjustment clauses are employed to increase rate levels. The customers who do not opt out after review of the final rate proposal would be committed to purchase as provided in their Subscription contracts. The 2002 Final Power Rates were approved by FERC in July 2003 but are in litigation in the Ninth Circuit Court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

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

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

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

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

The FB-CRAC is designed to restore, on a forecasted basis, Bonneville's financial reserves to certain fiscal year-end reserve levels ("Reserve Targets"). A rate level increase under the FB-CRAC is implemented for an entire fiscal year and occurs during a subject fiscal year only if Bonneville's financial forecast made in the third quarter of the prior fiscal year indicates that the accumulated net revenues for the beginning of the subject fiscal year will be below the accumulated net revenue equivalent of the applicable Reserve Target. 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 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 Rates, Bonneville is to determine 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 originally contracted aggregate purchase obligations to a substantial degree. The remaining 200-300 megawatts of Subscription power sales under the Residential Exchange Settlement Agreements are subject to the LB-CRAC, FB-CRAC and the SN-CRAC.

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. The four subsequent semiannual LB-CRAC adjustments were, respectively, about 39%, 32%, 39%, and 21% of base rates. Bonneville expects that the LB-CRAC for the six months beginning April 1, 2004, will be about 25% of base rates. Bonneville expects that the LB-CRAC adjustments will average about 31% of base rates for the remaining two years of the rate period.

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 was roughly 11% of base rates for those contracts to which the FB-CRAC applies. The FB-CRAC was triggered again for fiscal year 2004, at roughly 12% of base rates. In connection with its proposal for an SN-CRAC rate level adjustment, Bonneville proposed to adjust the financial conditions under which the FB-CRAC would trigger. Such changes would assure that the conditions for the SN-CRAC rate level adjustment are not met unless the FB-CRAC conditions have been met. FERC approved the foregoing modification to the FB-CRAC on May 10, 2004. FERC's approval of the FB-CRAC modification is subject to review in Federal appellate court and Bonneville expects that litigation will be filed challenging such modification and FERC's approval thereof.

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 rate period, in each case excluding transmission. Beginning April 1, 2003, the cumulative average Subscription power rate levels were about 3.0-3.4 cents per kilowatt-hour, excluding transmission, and for the first six months of fiscal year 2004 the cumulative average Subscription power rate levels are about 3.0-3.4 cents per kilowatt-hour.

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, thereby triggering a process to develop an SN-CRAC rate level adjustment proposal. In June 2003, Bonneville issued a final proposal and record of decision for the SN-CRAC rate level adjustment and submitted the proposal and record of decision to FERC for review and approval. In view of improved water conditions in fiscal year 2003, better than previously expected revenues from discretionary power sales, and effects of cost management and financial liquidity actions, the final proposed SN-CRAC rate level increase for fiscal years 2004-2006 was less than the SN-CRAC rate level adjustment Bonneville initially proposed. Bonneville estimates that the final SN-CRAC rate level adjustment 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. On May 10, 2004, FERC approved the SN-CRAC rate level adjustment proposed by Bonneville. FERC's approval of the SN-CRAC rate level adjustment is subject to review in Federal appellate court and Bonneville expects that litigation will be filed challenging the SN-CRAC rate level adjustment and FERC's approval thereof.

The final SN-CRAC rate level adjustment is a variable contingent mechanism where the calculation of the actual rate level adjustment for a fiscal year would 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 accumulated net revenues for the fiscal year preceding the fiscal year in which the rate level adjustment is to be in effect. Thus, the first year (fiscal year 2004) rate level adjustment under the final SN-CRAC rate level adjustment was determined in August 2003 on the basis of then available financial forecasts of fiscal year end 2003 accumulated net revenues. Under that determination, Bonneville's SN-CRAC rate level adjustment for fiscal year 2004 is expected to 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 2.2 percent over fiscal year 2003 levels. This is less than Bonneville forecasted when it submitted the final SN-CRAC rate level adjustment to FERC in June 2003.

In developing the SN-CRAC rate level adjustment Bonneville estimated that the adjustment would assure that Bonneville has an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time in the three fiscal years beginning October 1, 2003. Such estimates are based on a number of forecasts that may not be realized and a number of assumptions that may prove erroneous. Notwithstanding the SN-CRAC rate level adjustment approved by FERC, Bonneville has reserved the ability to develop an additional SN-CRAC rate level adjustment should the conditions of the Final 2002 Power Rate Proposal be met: 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. Whether and the extent to which Bonneville would increase rate levels under an additional SN-CRAC adjustment would be determined in view of all facts and circumstances at the time.

Assuming the expected effects of the final SN-CRAC rate level adjustment and expected rate level adjustments under the FB-CRAC and LB-CRAC, Bonneville's average power rates for fiscal years 2004-2006 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 in this Appendix A, the rate level increases under the rate adjustment mechanisms vary depending on the type of Subscription power sales contract. Some contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms.

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

Recovery of Stranded Power Function Costs

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

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

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

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

Changes in the Regulation of Regional Retail Power Markets

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

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

Under some retail access approaches, utilities would have a reduced ability to recover power costs in reliance on their exclusive ownership of distribution facilities for retail service to their end-users.

TRANSMISSION BUSINESS LINE

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately- and publicly-owned utilities, power marketers, power generators and others. Bonneville's revenues from the sale of transmission and related services accounted for roughly 15 percent of Bonneville's overall revenues in fiscal year 2003.

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

While it is difficult to generalize as to the cost of transmission service needed to effect various power transactions, a useful point of reference may be the cost borne by certain Regional full requirements Preference Customers of Bonneville's. These customers pay roughly $4.00 to $4.50 per megawatt hour for Network Integration transmission and ancillary services to Bonneville to provide delivery of firm power that Bonneville sells at the PF rate, which is currently priced at roughly $30.00 to $34.00 per megawatt hour, depending on type of service and exclusive of transmission. Other customers, e.g., marketers using Point-to-Point service to transmit non-Federal power, pay approximately $3.50 per megawatt hour for transmission and ancillary services.

Bonneville's Transmission System

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

The Federal 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 Bonneville's Power Business Line for its out-of-Region sales; entities that buy and sell non-Federal power in the Region, such as Regional IOUs, Preference Customers, extra-Regional IOUs, independent power producers, aggregators and marketers; in-Region purchasers of Federal System power such as Preference Customers and DSIs; and generators, power marketers and utilities that seek to transmit power into, out of, or through the Region.

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

Bonneville continually monitors its transmission system and evaluates cost-effective responses needed for system stability and reliability on a long-term planning basis. A number of conditions, actions, and events could affect the electric transfer capability of Bonneville's transmission system and diminish the capacity of the system to a level that could require remedial measures. For example, operating conditions such as weather, system outages and changes in generation and load patterns, may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of users of the transmission system, including Bonneville's Power Business Line.

Transmission Infrastructure Program

Given its importance to electrical service both in the Pacific Northwest Region and the wider western United States, the Federal Transmission System must have the capacity to carry the power around the clock, in compliance with national reliability standards, and do this under a variety of stress conditions. Load growth on the system has been about 1.8% a year and transmission use has grown about 2% a year, since the late 1980's. Furthermore, deregulation of the wholesale power industry in 1992 altered the way utilities do business. Utilities are now required to operate and manage their power and transmission systems as separate businesses, guaranteeing that all power generators have equal access to transmission. This increased the amount of transmission system transactions by nearly 5 percent a year while peak use of the electrical system increased by almost 2 percent a year.

In light of the increasing demand on the Federal Transmission System, critical paths on the Northwest transmission grid are now congested and the system is nearing or at capacity. With increased congestion, computer models and monitoring show the grid to be harder to control after an emergency. Congestion is not only a risk to electric system reliability, it reduces the ability of Bonneville, as the power marketing agent for the hydroelectric power from the Federally-owned hydroelectric dams in Pacific Northwest, to get low-cost energy to market.

In view of the foregoing considerations, Bonneville developed a "Transmission Infrastructure Program" to evaluate a number of key infrastructure projects to improve the reliability of the Northwest transmission system and to meet the Region's future power needs. In 2001, Bonneville identified a number of projects needed to shore up the Region's transmission system. Bonneville submitted the proposed projects to a panel of Regional transmission experts for review to ensure the projects are necessary, properly prioritized, placed into operation when needed, and designed to provide cost-effective, reliable service to the Region.

Bonneville has completed construction of the highest priority system reliability upgrade project and has initiated construction on the next two highest priority system reliability upgrade projects. With regard to congestion and reliability investments, Bonneville expects to finance such investments with a mix of United States Treasury borrowing authority and sources of non-United States Treasury financing, such as lease-purchase arrrangements.

In March 2004, Bonneville entered into a lease purchase transaction with Northwest Infrastructure Financing Corporation ("NIFC") for construction and financing of a $109 million dollar transmission line and related facilities. In return for exclusive use and possession of such project, Bonneville is unconditionally obligated to make lease rental payments to NIFC for a period of 30 years. Bonneville has an option to acquire the project at the end of the lease period for a nominal additional payment.

To obtain funds for project construction, NIFC issued publicly offered bonds in the amount of $119.585 million. Payment of the bonds is secured solely by the lease rental payments from Bonneville. Bonneville will record its obligation under the lease purchase arrangement as a debt-like obligation in its accounting statements. Bonneville may enter into similar transactions in the future, although Bonneville has not identified any specific projects that would be financed in such a manner. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Proposals for Federal Legislation and Administrative Action Relating to Bonneville." While Bonneville has focused its transmission infrastructure efforts primarily on transmission projects needed to maintain reliability, other transmission projects are proposed that will provide additional, long-term firm transmission service for new power generation ("generation integration projects"). These transmission project proposals are on hold but are expected to move forward when funding approaches can be finalized. With regard to the financing of the foregoing generation integration projects, Bonneville's current policy is to require that those applicants requesting that Bonneville provide transmission for new generating facilities bear the risk of stranded transmission interconnection costs by prepaying the related transmission investments and obtaining credits to their transmission bills from Bonneville.

Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $302 million a year over the four fiscal years commencing October 1, 2003.

Non-discriminatory Transmission Access and Separation of the Business Lines

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

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

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

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

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

Bonneville's Transmission and Ancillary Service Rates

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

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

Bonneville's transmission and ancillary services rates for fiscal years 2004-2005 were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. In addition to approving Bonneville's transmission rates under the Northwest Power Act, FERC stated that the rates and tariffs fulfill standards for open, nondiscriminatory transmission access. The 2004 transmission rates were not challenged in litigation. In Fall 2004, Bonneville will commence proceedings for transmission rates and tariffs for the next transmission rate period.

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 a form of governance and a geographic scope of a nonprofit RTO now named RTO West (and proposed to be re-named "Grid West") for the transmission systems of transmission owners willing to participate and located within the United States portion of the Northwest Power Pool ("Stage 1 proposal"). This region is composed of Washington, Oregon, Idaho, Utah, Nevada, Montana and western Wyoming. On April 26, 2001, FERC granted preliminary approval of the proposals for governance and geographic scope. On March 29, 2002, the Filing Utilities, along with the British Columbia Hydro and Power Authority, filed additional elements of their RTO West proposal ("Stage 2 proposal") for FERC approval. In September 2002, FERC approved a majority of the Stage 2 proposal, including the Company Rates concept (described briefly below) with an 8-year transition period, voluntary conversion of existing transmission contracts to RTO West Tariff service, and a modified congestion management proposal. FERC rejected a broad proposal for all the terms of the operating agreement to govern in the event of a conflict with the RTO West Tariff. However, FERC acknowledged the Filing Utilities' interest in protecting certain elements of their proposed arrangement from future, unilateral FERC modification and indicated its willingness to consider a more narrowly defined list of provisions that warranted protection.

Under the 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. For a period of at least eight years after commencement of service by RTO West ("Company Rate Period"), costs for the use of Bonneville's transmission facilities would be recovered through Bonneville's own "Company Rates." ("Company Rates" are rates that are individually established to recover each owner's transmission revenue requirement under laws applicable to the related owner.) The draft operating agreement provides that Bonneville would set its own costs and billing determinants, which would be used to derive Company Rates for recovery of Bonneville's costs from its own loads. If, after the Company Rate Period, RTO West determines to implement a rate structure other than the Company Rate, Bonneville would continue to establish its charges to be recovered by RTO West through rates adequate to (i) meet Bonneville's annual revenue requirement and (ii) satisfy all obligations of Bonneville for the net billing and payment of costs for nuclear generating projects owned in whole or in part by Energy Northwest or the Eugene Water and Electric Board. 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 its April 2001 order, FERC acknowledged the need to provide assurances and protections to Bonneville with respect to its ability to continue to meet its statutory, treaty, contract 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 of 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.

In its April 2001 order, FERC rejected a 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 its September 2002 order, FERC reversed itself and determined that the Filing Utilities could propose limited liability provisions when they file the RTO West tariff. The RTO West tariff has not yet been filed. 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 Grid West. Depending on the extent to which FERC approves tariff provisions limiting liability, 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 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. The petition did not identify specific grounds for the review. On June 19, 2003, the United States Court of Appeals for the District of Columbia dismissed the case on the basis that the case was not ripe for review.

The Filing Utilities have recently resumed their engagement with regional stakeholders through the Regional Representatives Group process to gauge the level of regional support for moving forward with the RTO West proposal as considered by FERC. These discussions are ongoing, and no further RTO West proposals have been filed with FERC.

Notwithstanding the foregoing efforts with respect to RTO West, a number of utilities and interested parties in the geographic area encompassed within the proposed reach of RTO West have expressed interest in developing a new RTO proposal. Early discussions have revolved around formation of an RTO which would have, at least initially, a more limited scope of operations than that proposed for RTO West. While Bonneville is participating in discussions with other utilities to develop the specifics of such a proposal, Bonneville is unable to predict the exact nature of such a proposal, or whether such a proposal would be submitted to FERC for approval and implemented.

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 total between $1 million and $2 million over several years, Bonneville cannot assure the ultimate level of costs that may be incurred under these statutes.

Other Applicable Laws

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

Columbia River Treaty

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

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

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

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

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

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

On February 2, 2004, President Bush issued the budget for Federal Government for fiscal year 2005. The budget narrative refers to the use by Bonneville of lease purchase arrangements for certain transmission facilities. The narrative states that Bonneville's "debt to the U.S. Treasury is currently limited by statute. To ensure the integrity and usefulness of this limitation, the Administration is considering proposing legislation calling for certain non-traditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville]'s statutory debt limit. This legislative proposal will be fully vetted with [Bonneville] stakeholders." Bonneville understands that such a proposal would be intended to limit future transactions only and would not be intended to affect its obligations under the Net Billing Agreements. Bonneville expects to participate in the preparation of any such legislative proposal.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such proposals, if enacted, could affect Bonneville's obligations with respect to the 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, 2003, Bonneville had repaid $5.5 billion of principal of the Federal System investment and has $6.6 billion principal amount outstanding with regard to such appropriated investments.

Bonneville Borrowing Authority

In February 2003, Congress enacted and the President signed into law a $700 million increase in Bonneville's authority to borrow from the United States Treasury. The new law 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.

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.70 billion of bonds were outstanding as of September 30, 2003. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 average megawatts. Of the $4.45 billion in United States Treasury borrowing authority, $1.25 billion is available for renewable resources and conservation purposes and $3.2 billion is available for Bonneville's transmission capital program and to implement the Administrator's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. As of September 30, 2003, the interest rates on the outstanding bonds ranged from 2.30% to 8.55% with a weighted average interest rate of approximately 5.32%. The original terms of the outstanding bonds vary from 3 to 40 years. The term of the bonds is limited by the average expected service life of the associated investment: 40 years for transmission facilities, 75 years for Corps and Bureau capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. 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" (or "Bonneville Proposal") to Energy Northwest. The proposal, which was agreed to by Energy Northwest, involves the extension of the final maturity of debt issued for the Columbia Generating Station. In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it also incorporated an increase in the average life of outstanding Projects 1 and 3 Net Billed Bonds as a refinancing program objective for any future refinancing of such bonds. See "PURPOSE OF ISSUANCE—Refunding Program" in the Official Statement.

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 (defined in the Official Statement) in return for payments by such customers to Energy Northwest to meet certain costs of its Columbia Generating Station, Project 1 (defined in the Official Statement) and Project 3 (defined in the Official Statement), 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.

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 2003 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.057 billion in fiscal year 2003, approximately $315 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Proposal through the use of cash flows derived from reduced Net Billed Project (defined in the Official Statement) 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. In accordance with the Debt Optimization Proposal, Bonneville plans to make similar advance amortization payments to the United States Treasury in fiscal year 2004 and in subsequent fiscal years. In addition to the advance amortization arising under the Debt Optimization Proposal, Bonneville amortized ahead of schedule about $13 million principal amount of its appropriations repayment responsibility relating to certain transmission facilities that Bonneville sold in fiscal year 2003.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments relating to Net Billed 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 other cash payments of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

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

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

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

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both the Bureau and the U.S. Fish and Wildlife Service ("Fish and Wildlife Service") to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Bureau federal system operations and maintenance activities. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2003 were $54 million for the Bureau, $129 million for the Corps, and $15 million for the Fish and Wildlife Service.

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

Hedging and Derivative Instrument Activities and Policies

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

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

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

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

Historical Federal System Financial Data

Federal System historical financial data for fiscal years 2001 through 2003 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information has been derived from the annual audited financial statements of the Federal System and should be read in conjunction with Appendix B-1. Federal System financial statements are prepared in conformity with generally accepted accounting principles. The audited Financial Statements of the Federal System (which include accounts of Bonneville as well as those of the generating facilities of the Corps and the Bureau, for which Bonneville is the power marketing agency) for the fiscal year ended September 30, 2003 are included as Appendix B-1 to the Official Statement and Bonneville's unaudited financial report for the six months ended March 31, 2004, is included as Appendix B-2 to the Official Statement.

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

Fiscal year ending September 30,	2003	2002	2001
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Publicly-owned utilities (1)	$1,723,138	$ 1,797,496	$ 939,362
Aluminum industry	18,480	58,454	420,694
Investor-owned utilities	435,709	377,789	700,836
Other power sales	1,211	1,293	972
Sales outside the Northwest Region (2)	628,242	638,261	1,084,077
Total Sales of Electric Power	2,806,780	2,873,293	3,145,940
Transmission and other revenues (3)	805,324	660,436	1,132,729
Total Operating Revenues	3,612,104	3,533,729	4,278,669
Operating Expenses:			
Bonneville O&M (4)	607,616	775,077	530,618
Purchased Power	1,043,009	1,286,867	2,291,961
Corps, Bureau and Fish & Wildlife O&M (5)	198,539	198,055	184,922
Non-Federal entities O&M — net billed (6)	208,535	167,026	208,839
Non-Federal entities O&M — non-net billed (7)	39,864	35,566	30,719
Total Operation and Maintenance	2,097,563	2,462,591	3,247,059
Net billed debt service	104,329	213,919	455,397
Non-net billed debt service	15,205	16,256	21,818
Non-Federal Projects Debt Service (8)	119,534	230,175	477,215
Federal Projects Depreciation	350,025	335,205	323,314
Residential Exchange (9)	143,967	143,983	68,082
Total Operating Expenses	2,711,089	3,171,954	4,115,670
Net Operating Revenues	901,015	361,775	162,999
Interest Expense:			
Appropriated Funds	280,094	325,551	317,213
Long-term debt	166,598	151,997	129,159
Capitalization Adjustment (10)	(67,703)	(67,356)	(68,784)
Allowance for funds used during construction	(33,398)	(57,892)	(45,679)
Net Interest Expense	345,591	352,300	331,909
Cumulative Effect of SFAS 133 (11)			(168,491)
Net Revenues/(Expenses)	$ 555,424	$ 9,475	$ (337,401)
Total Sales (unaudited) — average megawatts (Net of Residential Exchange Program)	10,764	11,732	10,302

(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 seasonal surplus 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. In addition, under Financial Accounting Standards Board Statement of Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville also recorded as revenue in Fiscal Years 2001, 2002 and 2003, positive Mark-to-Market Amounts of $55.3 million, $38.4 million and $47.9 million, respectively. See Footnote 11 below.

(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's 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 SFAS 133, Bonneville recorded a cumulative-effect adjustment of $168,491,000 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 $555 million in fiscal year 2003, an increase of approximately $545 million over fiscal year 2002. Implementation of the Debt Optimization Proposal and other debt management actions contributed significantly to the substantial increase in net revenues. Without the program, other debt management actions, and the effects of SFAS 133, net revenues would have been $37 million for fiscal year 2003. Total operating revenues increased by $78 million, or 2%, from the previous fiscal year because of greater sales to Regional IOUs and increased United States Treasury credits derived under section 4(h)(10)(C) of the Northwest Power Act for fish mitigation, even though there was both reduced hydro generation and reduced power sales when compared to fiscal year 2002. However, the average price for discretionary surplus power sales rose from $26 per megawatt hour to $37 per megawatt hour, an increase of 42%. United States Treasury credits under section 4(h)(10)(C) of the Northwest Power Act increased from $38 million to $175 million in 2003, including $79 million from the Fish Cost Contingency Fund, which was not accessed in fiscal year 2002 and is now fully depleted. Credits for fish mitigation increased due to below-average water conditions and increased power purchases that result from reduced hydro supply. For a description of 4(h)(10)(C) 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 2003 were approximately $460 million lower as compared to fiscal year 2002, a decrease of about 14%. This was largely due to decreased Non-Federal Projects Debt Service, which decreased by $111 million or 48% because of the deferral of some principal payments due in fiscal year 2003 into the future, primarily as a result of continued implementation of the Debt Optimization Proposal. Lower interest rates through refinancing some of the Non-Federal debt also contributed to the decline in debt service. Net Interest Expense on Federal debt declined by $7 million compared to fiscal year 2002 due to generally lower interest rates on borrowings from the United States Treasury to finance federal generating and transmission projects. Total operations and maintenance costs, excluding Purchased Power, also decreased by $121 million, or 10% from the previous year. Lower bad debt expense and general and administrative expense were the main factors that led to this decrease. Purchased Power also decreased by $244 million, or 19%, in view of comparatively lower prices for the power purchased by Bonneville and the release of Bonneville from certain power purchase commitments as the result of a settlement between Bonneville and Enron Power Marketing Corp. in its bankruptcy proceedings.

In fiscal year 2002, Bonneville had positive net revenues of almost $10 million, 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 sales to publicly-owned utilities, which in fiscal year 2002 increased by $858 million, or 91%, due to a substantial rate increase at the beginning of the new rate period (October 1, 2002), and an increase in the amount of power Bonneville sold to this customer class. The $472 million, or 42%, decline over fiscal year 2001 in revenues from transmission and other related services was the result of lower estimated Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act as these repayment credits declined by 94% as noted immediately above. Applicable criteria did not permit use of the Contingency Fund whereas $247 million was drawn from the fund, in the form of United States Treasury repayment credits, during fiscal year 2001.

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

Statement of Non-Federal Project Debt Service Coverage

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

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

Fiscal Years ending September 30,	2003	2002	2001
Total Operating Revenues	$3,612,104	$ 3,533,729	$4,278,669
Less: Operating Expense[1]	2,042,991	2,408,520	3,130,219
Net Funds Available for Non-Federal Project Debt Service	1,569,113	1,125,209	1,148,450
Less: Total Non-Federal Project Debt Service[2]	119,534	230,175	477,215
Revenue Available for Treasury	1,449,579	895,034	671,235
Amount Paid to Treasury:			
Corps and Bureau O&M[3]	198,539	198,055	184,922
Net Interest Expense[4]	345,591	352,300	331,909
Capitalization Adjustment[5]	67,703	67,356	68,784
Allowance for Funds Used During Construction[4] [6]	18,641	15,061	12,479
Amortization of Principal	543,747	505,012	210,127
Total Amount Allocated for Payment to Treasury[7]	1,174,221	1,137,784	808,221
Revenues Available for Other Purposes[8]	275,358	(242,750)	(136,986)
Non-Federal Project Debt Service Coverage Ratio[9]	13.1	4.9	2.4
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[10]	1.7	1.3	1.2

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

(2) Includes net billed and non-net billed debt service. Non-net billed debt service amounted to $21.8 million, $16.3 million and $15.2 million for fiscal years 2001, 2002 and 2003, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Bureau and Fish & Wildlife for fiscal years 2001, 2002 and 2003. 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 2001, 2002 and 2003 were $729 million, $1.056 billion and $1.057 billion, respectively. In fiscal years 2001, 2002 and 2003, respectively, direct payments to the Corps, Bureau and Fish & Wildlife for operations and maintenance were included in the amount of (i) $117 million, $132 million and $129 million for the Corps, (ii) $55 million, $51 million and $54 million for the Bureau, and (iii) $13 million, $15 million and $15 million for Fish & Wildlife, respectively. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(8) Revenues Available For Other Purposes approximates the change in reserves from year to year. Reserves were $811 million at the end of fiscal year 2000 (not depicted) and $511 million at the end of fiscal year 2003.

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

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

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

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

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

Fiscal years ending September 30,	2003	2002	2001
Operating Revenues from Publicly-Owned Utilities[2]	$ 1,723,138	$1,797,496	$ 939,362
Net Billing Obligations:			
Net Billing Credits	476,947	610,180	675,938
Payments in Lieu of Net Billing[3]	(140,261)	(111,329)	57,283
Net Billing Obligations — Cash	336,686	498,851	733,221
Net Billing Expenditures:			
Net Billed Debt Service	104,329	213,919	455,397
Other Entities O&M — Net Billed	208,535	167,026	208,839
Increase/(Decrease) in Prepaid Expense	23,822	117,906	68,985
Net Billing Expenditures — Accrual	$ 336,686	$ 498,851	$ 733,221

(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. See “SECURITY FOR THE NET BILLED BONDS—Payment Procedures” in the Official Statement.

BONNEVILLE LITIGATION

Kaiser Aluminum Bankruptcy

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

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

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

PGET Bankruptcy

In July 2003, PG&E Energy Trading – Power L.P. (“PGET”), a non-utility power marketer and affiliate of PG&E, which in turn is a California utility, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Maryland. As a result, Bonneville has notified PGET that Bonneville has terminated all power sales and purchase transactions with PGET. Bonneville also notified PGET of Bonneville’s calculation of a termination payment owed by PGET to Bonneville in the amount of approximately $24 million. Apart from relatively small dollar amounts relating to two short term power transactions, undelivered power by PGET, and accounts receivable owing to Bonneville at the time of filing, virtually all of the termination payment calculated by Bonneville is attributable to the mark-to-market value of a single 100 megawatt Augmentation Purchase by Bonneville. At the time of Bonneville's notification of termination, there were approximately three years of remaining performance under the Augmentation Purchase. Bonneville is unable to predict whether or the extent to which it will receive payment under the terminated transactions. On behalf of Bonneville, the United States Department of Justice has filed a proof-of-claim for approximately $24 million.

Longview Aluminum Bankruptcy

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

In February 2003, Longview Aluminum filed two petitions for review against Bonneville in the Ninth Circuit Court. These petitions have been dismissed with prejudice. On March 4, 2003, Longview filed for bankruptcy protection under the federal bankruptcy laws. Bonneville has filed proofs-of-claim totaling approximately $63 million under power and transmission sales agreements.

GNA Bankruptcy

On December 22, 2003, Golden Northwest Aluminum ("GNA"), a holding company that contracts on behalf of two DSIs with Bonneville, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Oregon. Bonneville estimates GNA owes Bonneville approximately $15.8 million on an unsecured basis for take-or-pay power purchase commitments in fiscal years 2002 and 2003. GNA has curtailed its load through June 2004, so its obligation to resume taking its contracted-for 236 megawatts of electric power from Bonneville will resume on July 1, 2004, absent further curtailment. If GNA elects to reject its remaining power purchase commitments with Bonneville, Bonneville would calculate its damages, if any, through the contract term of September 30, 2006.

Mirant Bankruptcy

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

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

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

Slice Litigation

On November 17, 2003, a group of Bonneville's Slice customers ("Benton Petitioners") filed a petition with the Ninth Circuit Court challenging Bonneville's final determinations of various adjustments and provisions under the Slice Agreements, including an annual Slice true-up adjustment charge. (The true-up charge is describe in "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads.") The Benton Petitioners assert that Bonneville's true-up adjustment charge and other determinations are inconsistent with the terms of the Slice contracts and that the Slice customers' audit of fiscal year 2002 charges revealed $83 million in charges that should have been made to other customers. The Benton Petitioners further assert that the court lacks jurisdiction to resolve the dispute because the Slice contracts require binding arbitration for such disputes. The Benton Petitioners have asked the court to determine whether it has jurisdiction over the dispute, and should the court determine that it does have jurisdiction, the Benton Petitioners have requested the court to stay the case pending completion of arbitration, or in the alternative, to appoint a special master to make factual determinations in the case.

On October 23, 2003, a group of Bonneville's full requirements Preference Customers, represented by the Northwest Requirements Utilities ("NRU"), a trade association, filed a petition in the Ninth Circuit Court challenging Bonneville's final determination of the true-up adjustment charge, final Slice rate and Slice revenue requirement for contract year 2002. The NRU Petitioners challenge aspects of Bonneville's Slice true-up adjustment charge and are concerned that if the Benton Petitioners were to prevail, the result would be a cost shift to the NRU Petitioners of up to $83 million. In addition, the petition also challenges the use of binding arbitration as a means to resolve a rate determination of Bonneville under the Northwest Power Act.

The petitions filed by the NRU Petitioners and Benton Petitioners have been consolidated. Although the court has set a briefing schedule, various motions are pending which may result in the schedule being modified.

On March 16, 2004, the NRU Petitioners filed an additional petition for review (NRU II). The reason for the new petition is that Bonneville's determination of the Slice true-up adjustment charge is an annual determination. On December 18, 2003, Bonneville made a final decision regarding its 2003 Slice true-up adjustment charge. The NRU Petitioners filed for review of the 2003 determination, and asked the court to stay the litigation pending the resolution of NRU I matter described above. The court has agreed to stay the case until December 13, 2004.

2002 Final Power Rates Challenge

Numerous Bonneville customers have filed petitions for review in the Ninth Circuit Court challenging Bonneville's 2002 Final Power Rates Proposal. The rates have been confirmed and approved by FERC. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Strategy Contracts Opt-Out Provisions." A schedule set out by the Ninth Circuit Court calls for briefing to be completed this summer.

City of Burbank, California v. United States

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

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

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

The claims filed by the cities under the Contract Disputes Act were denied by Bonneville's Contracting Officer, and in April 2003, the cities filed an appeal with the Department of Energy Contract Board of Appeals. In response, Bonneville filed a motion to dismiss for lack of subject matter jurisdiction, and in January 2004 the motion was denied. A hearing has been set for June 2004.

Residential Exchange Program Litigation

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

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

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

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

In October 2003, Bonneville and members of the two major utility groups in the region signed a conditional settlement of the foregoing litigation, which if effected, would have reduced Bonneville's Subscription power rates for public utilities and DSIs by 7.4 percent below fiscal year 2003 average rates. The settlement required the approval of numerous Preference Customers by a specified date and the necessary approvals were not obtained. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates." As a result of the lack of settlement, a briefing schedule has been established in the cases involving challenges to the Residential Exchange Settlement Agreements. On March 15, 2004, Bonneville filed an unopposed motion to dismiss the challenges to Bonneville's *pro forma* RPSAs. The unopposed motion is currently pending with the court.

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), the Pacific Northwest Generating Cooperative ("PNGC") and its members, and Puget Sound Energy. 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. PNGC and Puget have filed a joint motion for voluntary dismissal of their petitions. The motion is currently pending before the court.

In a related matter, Puget Sound Energy, Inc. ("Puget") 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. Puget filed a motion for voluntary dismissal of its petition. The court granted the motion, dismissing the petition on March 29, 2004.

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

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

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

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

In May 2001, the Corps filed a new Record of Consultation and Statement of Decision ("ROCASOD") with the court. As expressed in the ROCASOD, the Corps agreed to consider additional measures in future years to improve water quality. In August 2001, plaintiffs filed an amended complaint challenging the adequacy of the new ROCASOD. Plaintiff's motion included a request for injunctive relief, in addition to a request for remand of the amended ROCASOD to the Corps. The Corps has informed Bonneville that the request for injunctive relief, if successful, could lead to increased funding or program requirements to meet state water quality standards. In November 2002, the district court heard oral arguments on summary judgment motions from plaintiffs and defendants. In January 2003, the court upheld the Corp's ROCASOD and ruled in favor of the Corps on the motions for summary judgment. In March 2003, plaintiffs appealed the court's January ruling upholding the Corps' ROCASOD.

Alturas Transmission Dispute

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

Southern California Edison v. Bonneville Power Administration

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

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

The current status of the claims is as follows:

Conversion from Sale to Exchange Mode. Rather than await a Contracting Officer's Decision, SCE filed an action in the Court of Federal Claims on December 26, 2002, based on its assertion that the claim should be "deemed denied" by Bonneville. SCE's complaint seeks damages in the amount of approximately $200,000,000. Bonneville filed a motion to dismiss for failure to state a claim for which relief can be granted. On October 24, 2003 the motion was denied. This litigation is now subject to a stay to facilitate discussions between the parties. If the litigation is not settled, it will proceed to discovery at the expiration of the stay.

Challenge to FPS-96R. Bonneville notified SCE that the claim was a challenge to Bonneville's rates, and such challenges are cognizable only in the Ninth Circuit Court of Appeals. On December 30, 2003, SCE filed a complaint in the Court of Federal Claims. The litigation is subject to a stay. If the litigation is not settled, Bonneville will file a motion to dismiss for lack of subject matter jurisdiction.

Termination for Default. In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. SCE filed an administrative claim with Bonneville under the Contract Disputes Act for wrongful termination in the amount of $20,000,000. In concert with the stay described above, SCE has agreed to defer further legal action on this claim.

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

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

In addition, Industrial Customers of Northwest Utilities have filed a separate related petition for review in the Ninth Circuit Court challenging Bonneville's SN-CRAC Record of Decision. A motion to dismiss the petition for lack of jurisdiction was denied. Industrial Customers of Northwest Utilities later filed a motion for voluntary dismissal. On March 17, 2004, the court granted the motion and dismissed the petition.

Yakama Nation Litigation

On June 24, 2003 the Yakama Nation, a tribal entity, filed a petition for review in the Ninth Circuit Court challenging a letter issued by Bonneville dated March 28, 2003. The letter addresses Bonneville's funding of measures in the Northwest Power Planning Council's Fish and Wildlife Program. The petition does not provide any information regarding the Yakama Nation's legal theories and includes no request for expedited review or injunctive relief. The case has been selected for inclusion in the Ninth Circuit Court's mediation program and the court has issued an order staying the case until July 1, 2004, pending settlement discussions.

Upper Columbia United Tribes Litigation

On December 18, 2003, the Upper Columbia United Tribes ("UCUT"), as well as certain other tribal petitioners, filed a petition for review in the Ninth Circuit Court challenging a letter from Bonneville to the Council. As with the Yakama Nation Litigation, above, the challenged letter addresses issues related to Bonneville's Fish and Wildlife Funding. The UCUT litigation is related to the Yakama Nation litigation, described above, and has been selected for inclusion in the Ninth Circuit Court's mediation program. Bonneville and the UCUT petitioners are currently engaged in settlement discussions, and the case is stayed until August 4, 2004.

ESA Litigation

National Wildlife Federation v. National Marine Fisheries Service

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

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

In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. The court's order gives NOAA Fisheries until early June 2004 to reconsider the biological opinion. In an additional ruling in June 2003, the court agreed to permit the 2000 Biological Opinion to remain in effect on an interim basis for up to one year (until early June 2004) while the 2000 Biological Opinion is on remand to NOAA Fisheries. In May 2004, the court granted NOAA Fisheries until late November 2004 to complete its review and modification of the 2000 Biological Opinion. In granting the time extension, the court also indicated that it may revisit and possibly shorten the time extension after consultation with affected parties in early June 2004.

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.

A motion for clarification was made to the court to define the geographic areas that must be addressed under the Biological Opinion. The court determined that the Action Agencies had undertaken the correct approach in defining such geographic areas. Currently, NOAA Fisheries and the Action Agencies are undertaking a collaborative effort with the states and tribes on the Biological Opinion process. This effort is primarily focused on an exchange of scientific data and ideas.

Alsea Valley Alliance v. Evans

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

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

In February 2004, the Ninth Circuit Court rejected the intervener environmental groups' motion to reinstate the Oregon Coast Coho as a listed species and upheld the District Court's invalidation of the listing decision. Thus, the Oregon Coast Coho are no longer listed under the ESA. Meanwhile, NOAA Fisheries continues to work on its review of its Hatchery Listing Policy as well as prior decisions to list 23 other salmon species in the Region,

Spill Reduction Litigation

In February 2004, two environmental groups delivered a formal "intent to sue" notice to Bonneville, the Corps and the Bureau. The notice, a prerequisite to filing suit under the ESA, is in response to Bonneville's proposal for a reduction in summer spill and consequent increase in electric power generation at four Federal System dams. The notice indicates that the environmental groups will file suit against the above listed agencies unless alleged ESA violations are cured within sixty days. NOAA Fisheries, one of the key decision makers in this matter, is expected to make a recommendation about the spill program in late spring 2004. While Bonneville's spill proposal would increase power generation at the four dams, Bonneville's power rates and current financial forecast do not assume any positive effects from the proposed reduction in summer spill.

Rates Litigation

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

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, of revenues and expenses, and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2003 and 2002, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2003, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2003, 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, 2003 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2003 (Schedule B) are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
November 7, 2003

Financial Statements

Statements of Revenues and Expenses

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

	2003	2002	2001
Operating Revenues			
Sales	**$3,328,277**	$3,407,404	$3,563,182
SFAS 133 mark-to-market	**55,265**	38,354	47,877
Miscellaneous Revenues	**53,678**	49,571	66,902
U.S. Treasury Credits for Fish	**174,884**	38,400	600,708
Total operating revenues	**3,612,104**	3,533,729	4,278,669
Operating Expenses			
Operations and maintenance	**1,198,521**	1,319,707	1,023,180
Purchased power	**1,043,009**	1,286,867	2,296,076
Nonfederal projects	**119,534**	230,175	473,100
Federal projects depreciation	**350,025**	335,205	323,314
Total operating expenses	**2,711,089**	3,171,954	4,115,670
Net operating revenues	**901,015**	361,775	162,999
Interest Expense			
Interest on federal investment:			
Appropriated funds	**212,391**	258,195	248,429
Long-term debt	**166,598**	151,997	129,159
Allowance for funds used during construction	**(33,398)**	(57,892)	(45,679)
Net interest expense	**345,591**	352,300	331,909
Net revenues (expenses) before cumulative effect of SFAS 133	**555,424**	9,475	(168,910)
Cumulative effect of SFAS 133	—	—	(168,491)
Net Revenues (Expenses)	**555,424**	9,475	(337,401)
Accumulated net (expenses) revenues, Oct. 1	**(211,676)**	(221,151)	132,810
Irrigation Assistance	—	—	(16,560)
Accumulated net revenues (expenses), Sept. 30	**$ 343,748**	$(211,676)	$(221,151)

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

	2003	2002
Utility Plant		
Completed plant	**$11,873,798**	$ 11,488,047
Accumulated depreciation	**(4,281,060)**	(4,052,117)
	7,592,738	7,435,930
Construction work in progress	**1,308,624**	1,200,179
Net utility plant	**8,901,362**	8,636,109
Nonfederal Projects		
Conservation	**47,246**	47,733
Hydro	**146,210**	167,080
Nuclear	**2,181,182**	2,127,907
Terminated hydro facilities	**28,840**	29,555
Terminated nuclear facilities	**3,883,115**	3,829,269
Total nonfederal projects	**6,286,593**	6,201,544
Decommissioning Cost	**126,000**	73,861
Conservation, net of accumulated amortization of $892,218 in 2003 and $831,631 in 2002	**374,443**	409,571
Fish and Wildlife, net of accumulated amortization of $133,743 in 2003 and $129,207 in 2002	**128,337**	134,204
Current Assets		
Cash	**503,026**	235,409
Accounts receivable, net of allowance	**146,768**	206,036
Accrued unbilled revenues	**190,416**	93,004
Materials and supplies, at average cost	**84,306**	85,107
Prepaid expenses	**288,068**	285,696
Total current assets	**1,212,584**	905,252
Other Assets	**230,756**	151,458
	$17,260,075	$ 16,511,999

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2003	2002
Capitalization and Long-Term Liabilities		
Accumulated net revenues (expenses)	**$ 343,748**	$ (211,676)
Federal appropriations	**4,607,476**	4,595,915
Capitalization adjustment	**2,124,697**	2,192,400
Long-term debt	**2,521,554**	2,563,141
Nonfederal projects debt	**6,045,931**	5,958,538
Decommissioning reserve	**126,000**	73,861
Total capitalization and long-term liabilities	**15,769,406**	15,172,179
Commitments and Contingencies (Notes 5 and 6)		
Current Liabilities		
Current portion of federal appropriations	**73,484**	46,687
Current portion of long-term debt	**176,200**	207,300
Current portion of nonfederal projects debt	**240,662**	243,006
Accounts payable and other current liabilities	**369,821**	343,425
Total current liabilities	**860,167**	840,418
Deferred Credits	**630,502**	499,402
	$17,260,075	$16,511,999

Statements of Changes in Capitalization and Long-Term Liabilities

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

	Accumulated Net (Expenses) Revenues	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2001	$ (221,151)	$ 4,670,930	$ 2,688,542	$ 6,171,949	$ 2,328,977	$15,639,247
Increase in federal appropriations for construction	—	168,583	—	—	—	168,583
Repayment of federal appropriations for 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)
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	$15,669,172
Increase in federal appropriations for construction	**—**	**99,418**	**—**	**—**	**—**	**99,418**
Repayment of federal appropriations for construction	**—**	**(61,060)**	**—**	**—**	**—**	**(61,060)**
Capitalization adjustment amortization	**—**	**—**	**—**	**—**	**(67,703)**	**(67,703)**
Increase in long-term debt	**—**	**—**	**470,000**	**—**	**—**	**470,000**
Repayment of long-term debt	**—**	**—**	**(482,687)**	**—**	**—**	**(482,687)**
Refinance of long-term debt	**—**	**—**	**(60,000)**	**—**	**—**	**(60,000)**
Net increase in nonfederal projects debt	**—**	**—**	**—**	**99,288**	**—**	**99,288**
Repayment of nonfederal projects debt	**—**	**—**	**—**	**(14,239)**	**—**	**(14,239)**
Decommissioning reserve	**—**	**—**	**—**	**—**	**52,139**	**52,139**
Net revenues	**555,424**	**—**	**—**	**—**	**—**	**555,424**
Balance at Sept. 30, 2003	**$ 343,748**	**$ 4,680,960**	**$ 2,697,754**	**$ 6,286,593**	**$ 2,250,697**	**$16,259,752**

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

	2003	2002	2001
Cash from Operating Activities			
Net revenues (expenses)	**$ 555,424**	$ 9,475	$ (337,401)
Expenses (income) not requiring cash:			
Depreciation	**269,957**	254,332	247,247
Amortization of conservation and fish and wildlife	**80,068**	78,047	76,067
Amortization of capitalization adjustment	**(67,703)**	(67,356)	(68,784)
AFUDC	**(33,398)**	(57,892)	(45,679)
(Increase) decrease in:			
Receivables and unbilled revenues	**(38,144)**	88,765	(31,283)
Materials and supplies	**801**	115	(20,930)
Prepaid expenses	**(2,372)**	(98,547)	(101,254)
Increase (decrease) in:			
Accounts payable and other current liabilities	**26,396**	(167,532)	138,687
IOU Settlement	**55,488**	—	—
Other	**(3,686)**	(6,399)	114,060
Cash provided by (used for) operating activities	**842,831**	33,008	(29,270)
Cash from Investment Activities			
Investment in:			
Utility plant	**(501,813)**	(487,030)	(399,220)
Conservation	**(25,458)**	(25,344)	141
Fish and wildlife	**(11,156)**	(6,102)	(16,493)
Other	**(2,458)**	—	—
Cash used for investment activities	**(540,885)**	(518,476)	(415,572)
Cash from Borrowing and Appropriations			
Increase in federal constructions appropriations	**99,418**	168,583	230,388
Repayment of federal construction appropriations	**(61,060)**	(196,911)	(125,469)
Irrigation assistance	**—**	—	(16,560)
Increase in long-term debt	**470,000**	390,000	260,000
Repayment of long-term debt	**(482,687)**	(308,101)	(84,658)
Refinance of long-term debt	**(60,000)**	—	—
Cash (used for) provided by borrowing and appropriations	**(34,329)**	53,571	263,701
Increase (Decrease) in cash	**267,617**	(431,897)	(181,141)
Beginning cash balance	**235,409**	667,306	848,447
Ending cash balance	**$ 503,026**	$ 235,409	$ 667,306

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.

Reclassifications

Certain reclassifications were made to the 2001 and 2002 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2003. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's power and transmission rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the 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. The court of appeals may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's general counsel that, if a rate were rejected, it would be remanded to BPA for reformulation.

BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every 6 months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of modified accumulated net revenues is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor. Some of these rate adjustment clauses are calculated initially on forward-looking estimates of market conditions, and adjustments are made after the fact when actual conditions are known. These 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, and 41 percent for the second half of fiscal 2002. The LB CRAC percentage increase was again revised to approximately 32 percent and 39 percent, respectively, for the 6-month periods beginning Oct. 1, 2002 and April 1, 2003.

On Sept. 30, 2003, BPA recognized a receivable of $4.6 million for the LB CRAC period ended March 31, 2003, and BPA estimated a receivable of zero for the LB CRAC period ended Sept. 30, 2003. On Sept. 30, 2002, BPA 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 period ended Sept. 30, 2002. The August 2002 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 requirements rates on top of the revised levels of the LB CRAC. The SN CRAC did not trigger in fiscal 2002 but did trigger in fiscal 2003, requiring an expedited rate case and resulting in rates that went into effect Oct. 1, 2003. BPA received interim approval of its recent SN CRAC rate proposal on Oct. 1, 2003, 105 FERC 61,006 (2003).

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percentage of BPA's power costs in exchange for a fixed percentage of generation and capabilities. Settlement of any over or under collection occurs in the subsequent year. For the fiscal 2003 settlement, BPA recognized a $30.4 million liability to be paid in fiscal 2004. For the fiscal 2002 settlement, BPA recognized a receivable of $49 million which was received in fiscal 2003.

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

BPA separately submitted a 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 Oct. 11, 2001, FERC granted final approval for corrections to 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) and granted final approval on July 21, 2003, 104, FERC 61,093 (2003).

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

SFAS 71 *Assets*

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 $4.7 billion, shown in the table on page 34, reflect an increase of $138 million from the prior year. Amortization of these costs aggregating $84 million in 2003, $299 million in 2002 and $259 million in 2001 is reflected in the Statements of Revenues and Expenses. If BPA were to discontinue using SFAS 71 it would simultaneously write down the SFAS 71 assets and amortize the remaining Appropriations Capitalization Adjustment resulting in a $2.6 billion net extraordinary loss being reported in the Statement of Revenues and Expenses.

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

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2003	2002
Nonfederal projects:		
Conservation	$ 47,246	$ 47,733
Terminated hydro facilities	28,840	29,555
Terminated nuclear facilities	3,883,115	3,829,269
Decommissioning cost	126,000	73,861
Conservation	374,443	409,571
Fish and wildlife	128,337	134,204
Settlements	105,313	17,594
Additional retirement contributions	23,400	36,800
	$ 4,716,694	$ 4,578,587

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.

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.

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 (1.8 percent to 6.3 percent in 2003, 3.3 percent to 6.5 percent in 2002 and 2.5 percent to 6.6 percent in 2001). Capitalization rates for other construction were approximately 6.3 percent in 2003, 6.5 percent in 2002 and 6.6 percent in 2001. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

BPA adopted SFAS 143, Accounting for Asset Retirement Obligations, on Oct. 1, 2002. SFAS 143 requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as a liability. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows.

Regulation

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

Also through regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2003, BPA has an estimated $146 million regulatory liability for these removal costs recorded in Accumulated Depreciation.

Asset Retirement Obligations Activity

Upon adoption of SFAS 143, BPA recorded an ARO for WNP-1 and Columbia Generating Station (See Decommissioning and Restoration Costs in Note 5, Commitments and Contingencies) for $72.1 million and adjusted the ARO for the Trojan plant to $57.8 million. Prior to the adoption of SFAS 143, the ARO associated with the Trojan plant was recorded on a nominal dollar basis at the time of its abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. With the adoption of SFAS 143, the regulatory asset (Decommissioning Cost) and the related ARO (Decommissioning Reserve) for the Trojan plant were reduced by $16.1 million to adjust the balances to an estimated fair value as required by SFAS 143. As of Sept. 30, 2003, the ARO for WNP-1, Columbia Generating Station and Trojan are $126 million. A corresponding amount representing a regulatory asset is included within Decommissioning Costs in the Balance Sheet.

The adoption of SFAS 143 did not result in a cumulative effect adjustment on the Statement of Revenue and Expenses as the effect was offset by a regulatory asset. $89.9 million has already been funded by BPA and held in trust relating to these AROs. The remaining amount will be collected in future rates.

The following presents the proforma effects to the balances and activities in AROs for the accounting periods reported herein had SFAS 143 been in effect for all periods:

Asset Retirement Obligations Activity

As of Sept. 30 — thousands of dollars

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

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 $466 million in 2003, $484 million in 2002 and $464 million in 2001.

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 $99 million in 2003, $259 million in 2002 and $61 million in 2001.

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 and prepayment agreements to mitigate the credit risk of financial instruments.

Credit Risk from California

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

BPA entered into certain power sales during the fiscal year 2001 through the Cal-PX for which BPA has not yet been paid. In addition BPA sold power and related services to the Cal-ISO during fiscal year 2001 for which BPA has not yet been paid in full. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, BPA has recorded provisions for uncollectible receivables and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, BPA is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

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 $35.1 million, $55.2 million and $8.0 million to the U.S. Treasury during 2003, 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $23.4 million as of Sept. 30, 2003, which represents the additional deferred contribution for 1998 through 2003. 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, 2003, BPA has scheduled additional payments totaling $119.7 million as follows.

Scheduled Additional CSRS Contributions
thousands of dollars

	Scheduled Contributions
2004	$ 30,900
2005	26,500
2006	23,200
2007	21,100
2008	18,000
	$119,700

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

Deferred Credits

Deferred credits consist of $153.2 million in advances from customers for projects which BPA is constructing on their behalf, $122.6 million paid to BPA from participants under the Third AC intertie capacity agreement, $94.0 million for the Enron settlement, $86.8 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $65.4 million leasing fees for fiber optic cable, $55.5 million for the IOU deferral, $27.0 million current fair market value of certain trading physical forward sales and purchases, written options and Libor interest rate swap transactions, $13.2 million in deferred CSRS, $12.8 million in unearned option premium revenue, and $.1 million in other miscellaneous long-term liabilities.

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. Deferred Third AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets.

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

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.

Payment of a portion of the 2003 IOU subscription settlement benefits were deferred to be paid in 2007 through 2011 unless they are reduced through billing credits offsetting the SN CRAC. The current portion of deferred credits to be recorded as revenue in 2004 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.

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, 2003 or 2002.

As of and for the years ended Sept. 30, 2003, 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

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

The following table reflects the written options outstanding.

Written Put Options

As of Sept. 30

	2003	2002
Put Options		
Outstanding	1,972,800 MWh	3,507,600 MWh
Average Strike Price	$40.33	$42.25

These options expire at various times through December 2003. BPA records written options on a mark-to-market basis and includes unrealized 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, 2003 and 2002. 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.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed Libor interest rate swaps to help manage interest rate risk related to its long-term debt portfolio.

In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for the next 10 years and receives a variable rate that changes weekly tied to LIBOR. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for the next 15 years and receives a variable rate that changes weekly tied to LIBOR. The net effect of the two swap transactions is essentially replacing variable rate debt with 3.3 percent fixed rate debt. The swap transaction does not qualify for special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. As of Sept. 30, 2003, BPA recorded a $7.9 million fair value loss in the Statement of Revenues and Expenses related to the interest rate swap transactions.

Adoption of Statement 133 and Related Guidance

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

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

For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2003, 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).

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

In April 2003, the FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends financial accounting and reporting for derivative instruments, including the accounting treatment for certain forward power sales and purchase contracts. SFAS 149 is effective for new contracts transacted after July 1, 2003. The normal purchase and sales exception previously allowed for bookout transactions under DIG issue C-15 was effectively eliminated by SFAS 149. However, under SFAS 149, BPA expects to qualify bookout transactions for the normal purchase and normal sale exception unless certain applicable criteria is not met. As of Sept. 30, 2003, the impact of adoption of SFAS 149 is immaterial.

For fiscal years 2003, 2002 and 2001, BPA recorded the following SFAS 133 fair value unrealized gain or loss in the Statement of Revenues and Expenses related to its derivative portfolio.

Fair Value Gains (Losses)
As of Sept. 30 — thousands of dollars

	2003	2002	2001
Physical Power Derivatives	$63,165	$ 38,354	$ 47,877
Interest Rate Swap	(7,900)	—	—
	$55,265	$ 38,354	$ 47,877

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $190 million, $93 million and $6 million at Sept. 30, 2003, 2002 and 2001 respectively. 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.

Fish Credits

The NW Power 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 BPA'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. BPA has taken this credit since 1995, in amounts that, with the exceptions of fiscal 2001 and 2003, ranged between $26 million and $60 million. Criteria was met permitting draws from the Fish Cost Contingency Fund of the $79 million and $247 million in 2003 and 2001 respectively. The fund is now depleted.

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), beginning in 1982 BPA entered into residential exchange contracts with most of its electric utility customers. These contracts were to result 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 October 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements, which provide financial benefits in place of residential exchange benefits for the period July 1, 2001, through Sept. 30, 2011. These agreements provide for both sales of power and monetary benefit payments to the IOUs. In fiscal 2003, BPA continued to negotiate a new settlement related to the IOUs benefits. See the Commitments and Contingencies section in Note 5 for additional information. The table below summarizes future IOU benefits as of Sept. 30, 2003, without the new settlement agreement discussed in Note 5.

IOU Exchange Benefits
thousands of dollars

	IOU Benefits
2004	$ 398,655
2005	473,865
2006	457,940
	$1,330,460

Includes approximately $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. Financial benefits beyond the current rate case period cannot currently be quantified.

Recent Accounting Pronouncements

In November 2002, FASB issued FASB Interpretation No. 45 (FIN 45), " Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others – an interpretation of FASB Statements No. 5, 57, and 107, and recission of FASB Interpretation No. 34." FIN 45 clarifies that a guarantor is required to recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. It also elaborates on the disclosures to be made by a guarantor on previously issued guarantees. Because of the guarantee associated with the nonfederal projects, BPA has historically recorded the associated debt, FIN 45 does not have a current effect on the FCRPS financial statements.

In January 2003, FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." FIN 46 clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The Interpretation differentiates between an entity with a majority voting interest (the previous requirement under ARB No. 51) and entities that have controlling financial interest through other arrangements that may not involve any voting interests and how both of these types of entities (variable interest entities) may need to be consolidated. FIN 46 is effective for variable interest entities created after Feb. 1, 2003. BPA is currently evaluating the effect of FIN 46 for arrangements which existed before Feb. 1, 2003. FIN 46 will be effective for BPA for fiscal year ending Sept. 30, 2004.

2. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which BPA is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to 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 $67.7 million for fiscal 2003, $67.4 million for 2002, and $68.8 million for 2001. The weighted-average interest rate was 7.0 percent in 2003 and 2002, and 6.9 percent in 2001.

Construction and replacement of Corps and Reclamation generating facilities historically have been financed through annual federal appropriations. Annual appropriations also were made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the 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 shows the term repayments on the remaining federal appropriations as of Sept. 30, 2003.

Federal Appropriations
thousands of dollars

Term Repayments	
2004	$ 73,484
2005	110,989
2006	68,939
2007	33,694
2008	10,913
2009+	4,382,941
	$4,680,960

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

3. Long-Term Debt

To finance its capital programs, BPA is authorized by Congress to issue to the U.S. Treasury up to $4.45 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $4.45 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2003, $305 million of conservation bonds and $2,393 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, 2003, for similar maturities exceeds carrying value by approximately $304 million, or 11 percent. The table at page 42 reflects the terms and amounts of long-term debt.

4. Nonfederal Projects

BPA has acquired all or part of the generating capability of five nuclear power plants. The contracts to acquire the generating capability of the projects, referred to as "net-billing agreements," require BPA to pay all or part of the annual projects' budgets, including operating expense and debt service, including projects that are not completed and/or not operating. BPA also has acquired all of the output of the Cowlitz Falls and 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 $223 million in fiscal 2003, $175 million in fiscal 2002, and $217 million in fiscal 2001 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $120 million, $230 million, and $473 million for 2003, 2002 and 2001, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses. Refinancing activities reduced debt service by $463 million, $319 million and $158 million for 2003, 2002, and 2001 respectively from rate case estimates.

The fair value of all Energy Northwest debt exceeds recorded value by $443 million or 7.3 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2003. All other nonfederal projects' debt approximates fair value as stated.

U.S. Treasury Bonds

Long-Term Debt (1) — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Construction and Fish & Wildlife	Conservation	Cumulative Total
January 1997	none	2004	6.80%	$ 30,000		$ 30,000
May 1999	none	2004	5.95%	26,200		56,200
June 2001 (2)	none	2004	4.75%	50,000		106,200
July 2000	none	2004	7.00%	50,000		156,200
September 1999 (2)	none	2004	6.40%	20,000		176,200
January 2000	none	2005	7.15%	53,500		229,700
January 2001	none	2005	5.65%	20,000		249,700
January 2001	none	2005	5.65%	25,000		274,700
March 2002	none	2005	4.60%	110,000		384,700
March 2002 (2)	none	2005	4.60%	30,000		414,700
May 1997	none	2005	6.90%	80,000		494,700
June 2002	none	2005	3.75%	60,000		554,700
June 2002	none	2005	3.75%		40,000	594,700
September 2000 (2)	none	2005	6.70%	20,000		614,700
October 2002	none	2005	3.00%	50,000		664,700
November 2002	none	2005	2.80%	40,000		704,700
April 2003 (2)	none	2006	2.40%	40,000		744,700
April 2003 (2)	none	2006	2.40%	25,000		769,700
July 2003	none	2006	2.30%	75,000		844,700
July 2003 (2)	none	2006	2.30%	30,000		874,700
August 1996	none	2006	7.05%	70,000		944,700
September 2000	none	2006	6.75%	40,000		984,700
September 2002	none	2006	3.05%	100,000		1,084,700
September 2002	none	2006	3.05%	30,000		1,114,700
September 2002 (2)	none	2006	3.05%	20,000		1,134,700
September 2003	none	2006	2.50%	20,000		1,154,700
September 2003 (2)	none	2006	2.50%	25,000		1,179,700
December 2002 (2)	none	2006	3.05%	40,000		1,219,700
April 2003	none	2007	2.90%	40,000		1,259,700
July 2003	none	2007	2.95%	25,000		1,284,700
August 1997	none	2007	6.65%	111,300		1,396,000
September 2003	none	2007	3.10%	20,000		1,416,000
April 1998	none	2008	6.00%	75,300		1,491,300
April 1998	none	2008	6.00%	25,000		1,516,300
August 1998	none	2008	5.75%	40,000		1,556,300
September 1998	none	2008	5.30%		104,300	1,660,600
May 1998	none	2009	6.00%	72,700		1,733,300
May 1998	none	2009	6.00%		37,700	1,771,000
July 1989	none	2009	8.55%		40,000	1,811,000
January 2001	none	2010	6.05%	60,000		1,871,000
January 2001	none	2010	6.05%	30,000		1,901,000
January 1996	2001	2011	6.70%		30,000	1,931,000
May 1998	none	2011	6.20%	40,000		1,971,000
June 2001	none	2011	5.95%	25,000		1,996,000
August 2001	none	2011	5.75%	50,000		2,046,000
November 1996	2001	2011	6.95%	40,000		2,086,000
January 1998	none	2013	6.10%	60,000		2,146,000
September 1998	none	2013	5.60%		52,800	2,198,800
February 1999	none	2014	5.90%	60,000		2,258,800
April 1998	2008	2028	6.65%	50,000		2,308,800
August 1998	none	2028	5.85%	106,500		2,415,300
August 1998	none	2028	5.85%	112,300		2,527,600
May 1998	2008	2032	6.70%	98,900		2,626,500
April 2003	2008	2033	5.55%	40,000		2,666,500
October 1993	1998	2033	6.85%	31,254		2,697,754
				$ 2,392,954	$ 304,800	$ 2,697,754
Less current portion						(176,200)
						$ 2,521,554

(1) The weighted average interest rate was 5.3 percent on outstanding long-term debt as of Sept. 30, 2003. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(2) Corps/Reclamation direct funding

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2003.

Nonfederal Projects
thousands of dollars

	Debt Repayments
2004	$ 265,135
2005	234,897
2006	253,632
2007	294,745
2008	307,953
2009+	4,930,231
	$6,286,593

5. Commitments and Contingencies

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.

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, 2003.

Purchase Power and Sales Commitments
thousands of dollars

	Purchase	Sales
2004	$ 662,918	$ 1,795,554
2005	704,548	1,602,745
2006	650,867	1,689,882
2007	48,882	87,393
2008	49,525	71,114
2009+	152,475	264,726
	$2,269,215	$5,511,414

Augmentation commitments run through 2006.

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. EFSEC has approved a revised plan prepared by Energy Northwest (December 2002 Site Restoration Plan) and the agreement should be executed by the end of December 2003. 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 most if not all site restoration costs. BPA has recorded an estimated liability of $25.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for WNP-1 decommissioning 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 and site restoration expenditures for Columbia Generating Station is $673 million (2003 dollars). BPA has recorded an estimated liability of $47.8 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking fund for the years ended Sept. 30, 2003, 2002 and 2001 were approximately $4.6 million per year. The sinking fund balance at Sept. 30, 2003, is $84 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, 2003, BPA's 30-percent share of this estimated remaining liability is $52.3 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143). The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements 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 2001, 2002 and 2003. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In 2002 and 2003, the decommissioning trust fund was used to fund a portion of the 2002 and 2003 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. These costs incorporate the impacts of SFAS 143 as implemented by PGE.

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 $6.6 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $13 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.5 million.

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

Endangered Species Act

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

Environmental Cleanup

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

Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2008.

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 $673 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin Project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2003.

Irrigation Assistance
thousands of dollars

	Distributions
2004	$ 739
2005	—
2006	—
2007	—
2008	2,950
2009+	669,787
	$673,476

On Dec. 11, 2002, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2001) from the Bureau of Reclamation. The numbers above, reflect that new schedule. They exclude $56.6 million assistance for Lower Teton which was never completed therefore never produced electricity and the administrator has no obligation to recover these costs.

IOU Monetary Benefits

During fiscal 2003, BPA and various customer representatives negotiated a proposed litigation settlement that would, among other things, affect IOU Monetary Benefits if the settlement becomes effective. (The proposed settlement would also dismiss a number of existing lawsuits, preclude certain future lawsuits, result in lower 2004 rates through a reduction in the SN CRAC, and bind parties to a number of other commitments that do not have a current financial statement impact.) Subsequent to year-end, on Oct. 21, 2003, BPA signed and offered the proposed settlement to regional customers that are party to the litigation that the proposed settlement would dismiss. Three parties signed the proposed settlement by Oct. 23, 2003, making the settlement effective, but subject to the condition of subsequent actions by a number of parties over the following 120 day period for the settlement to remain in effect. During this 120-day period, in order for the proposed settlement to remain in effect, a number of other parties must sign the appropriate settlement agreements.

Under the proposed settlement, the method for establishing the IOUs' Monetary Benefits for the fiscal 2007 through 2011 period would be established, and BPA's option to provide power to the IOUs during that period would be relinquished. A portion of IOU Monetary Benefits currently scheduled to be paid out in fiscal 2004 through 2006 would be deferred to 2007 through 2011, and most of the deferral amounts could no longer be reduced through billing credits offsetting the IOUs' SN CRAC charges. The settlement would also eliminate the $200 million risk contingency payment owed to two IOUs that have load reduction contracts. However, if the settlement is terminated as the result of certain events during the 120-day period, BPA would expect to have to pay the $200 million in accordance with the terms of the contracts. The $200 million is considered augmentation costs and, if paid, would then be collected through the LB CRAC.

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. Inter-segment 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 $1,249 million for 2003 ($3,612 million Operating Revenues less $55 million SFAS 133 mark-to-market, $175 million U.S. Treasury Credits for Fish, $1,199 million Operations and Maintenance and $1,043 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

Major Customers

During 2003, 2002 and 2001, 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
2003				
Unaffiliated Revenues	$ 3,059,386	$ 552,718	$ —	$ 3,612,104
Intersegment Revenues	85,425	110,884	(196,309)	—
Operating Revenues	$ 3,144,811	$ 663,602	$ (196,309)	$ 3,612,104
Net Operating Margin	$ 1,184,846	$ 337,353	$ (272,818)	$ 1,249,381
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

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2003 — 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	$ 5,787,429	$ 5,360,934	$ 426,495	$ 5,787,429	$ —	$ —	$ —
Bureau of Reclamation							
Boise	138,215	17,169	3,920	21,089	(363)	68,219	67,856
Columbia Basin	1,930,254	1,234,556	33,140	1,267,696	494,514	143,955	638,469
Green Springs	35,579	11,178	62	11,240	9,934	8,070	18,004
Hungry Horse	148,957	121,808	223	122,031	—	—	—
Minidoka-Palisades	382,454	109,789	787	110,576	386	72,966	73,352
Yakima	258,946	6,139	60	6,199	13,821	127,511	141,332
Total Bureau Projects	2,894,405	1,500,639	38,192	1,538,831	518,292	420,721	939,013
Corps of Engineers							
Albeni Falls	48,868	42,665	1,535	44,200	—	—	—
Bonneville	1,382,775	878,749	99,719	978,468	—	—	—
Chief Joseph	625,023	568,853	15,700	584,553	—	163	163
Cougar	104,922	20,332	42,396	62,728	—	3,288	3,288
Detroit-Big Cliff	70,272	41,220	2,926	44,146	—	5,050	5,050
Dworshak	375,281	316,522	2,095	318,617	—	—	—
Green Peter-Foster	95,966	49,787	5,851	55,638	—	6,222	6,222
Hills Creek	51,077	18,394	998	19,392	—	4,616	4,616
Ice Harbor	217,312	151,874	5,764	157,638	—	—	—
John Day	649,960	485,992	16,579	502,571	—	—	—
Libby	576,024	430,559	2,797	433,356	—	—	—
Little Goose	253,747	209,179	2,921	212,100	—	—	—
Lookout Point-Dexter	109,199	49,738	7,184	56,922	—	1,498	1,498
Lost Creek	149,983	26,988	35	27,023	—	2,190	2,190
Lower Granite	408,326	329,683	5,002	334,685	—	—	—
Lower Monumental	271,464	226,219	2,572	228,791	—	—	—
McNary	376,127	288,752	13,463	302,215	—	—	—
The Dalles	412,311	304,378	58,489	362,867	—	—	—
Lower Snake	261,019	255,964	2,502	258,466	—	—	—
Columbia River Fish Bypass	885,643	316,377	527,698	844,075	—	—	—
Total Corps Projects	7,325,299	5,012,225	816,226	5,828,451	—	23,027	23,027
AFUDC on Direct Funded Projects	27,711	—	27,711	27,711	—	—	—
Irrigation Assistance at 12 Projects having no power generation	196,150	—	—	—	153,381	42,769	196,150
Total Plant Investment	16,230,994	11,873,798	1,308,624	13,182,422	671,673	486,517	1,158,190
Repayment Obligation Retained by Columbia Basin Project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton Project	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$ 16,314,740	**$ 11,876,634**	**$ 1,315,893**	**$ 13,192,527**	**$ 730,049**	**$ 490,198**	**$ 1,220,247**

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

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

	Non-reimbursable *(unaudited)*					
	Navigation	Flood Control	Fish and Wildlife	Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	49,270	15.00%
Columbia Basin	—	17,116	6,073	175	725	91.29%
Green Springs	—	—	—	—	6,335	59.51%
Hungry Horse	—	26,926	—	—	—	81.92%
Minidoka-Palisades	—	64,397	2,568	10,494	121,067	29.01%
Yakima	—	2,479	51,044	289	57,603	7.73%
Total Bureau Projects	—	110,918	59,685	10,958	235,000	71.07%
Corps of Engineers						
Albeni Falls	180	271	—	4,217	—	90.45%
Bonneville	400,979	—	—	1,266	2,062	70.76%
Chief Joseph	—	—	4,977	6,330	29,000	93.53%
Cougar	548	38,358	—	—	—	59.79%
Detroit-Big Cliff	219	20,857	—	—	—	62.82%
Dworshak	9,636	31,561	—	15,467	—	84.90%
Green Peter-Foster	366	30,377	—	1,693	1,670	57.98%
Hills Creek	630	26,439	—	—	—	37.97%
Ice Harbor	56,159	—	—	3,515	—	72.54%
John Day	90,980	18,038	—	11,962	26,409	77.32%
Libby	—	95,190	876	15,965	30,637	75.23%
Little Goose	34,913	—	—	4,130	2,604	83.59%
Lookout Point-Dexter	749	49,428	—	602	—	52.13%
Lost Creek	—	53,105	24,541	29,481	13,643	18.02%
Lower Granite	52,600	—	—	13,199	7,842	81.97%
Lower Monumental	39,382	—	—	2,874	417	84.28%
McNary	69,004	—	—	4,908	—	80.35%
The Dalles	47,344	—	—	2,078	22	88.01%
Lower Snake	2,553	—	—	—	—	99.02%
Columbia River Fish Bypass	38,798	2,770	—	—	—	95.31%
Total Corps Projects	845,040	366,394	30,394	117,687	114,306	79.57%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.20%
Total Plant Investment	845,040	477,312	90,079	128,645	349,306	85.36%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project	—	9,151	—	2,433	—	80.70%
	$ 845,040	**$ 486,463**	**$ 90,079**	**$ 131,078**	**$ 349,306**	**85.34%**

QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2004
Federal Columbia River Power System

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

	March 31	
	2004	2003
Utility Plant		
Completed plant	**$11,959,132**	$11,576,469
Accumulated depreciation	**(4,408,844)**	(4,174,785)
	7,550,288	7,401,684
Construction work in progress	**1,410,943**	1,290,326
Net utility plant	**8,961,231**	8,692,010
Nonfederal Projects		
Conservation	**43,761**	45,303
Hydro	**146,210**	163,215
Nuclear	**2,181,772**	2,129,235
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,889,847**	3,837,979
Total nonfederal projects	**6,289,680**	6,204,572
Decommissioning Cost	**123,935**	73,726
Conservation, net of accumulated amortization	**357,365**	391,701
Fish & Wildlife, net of accumulated amortization	**124,681**	126,475
Current Assets		
Cash	**969,776**	458,377
Accounts receivable, net of allowance	**108,395**	129,115
Accrued unbilled revenues	**209,167**	269,005
Materials and supplies, at average cost	**83,678**	86,150
Prepaid expenses	**118,666**	127,563
Total current assets	**1,489,682**	1,070,210
Other Assets	**275,274**	165,572
	$17,621,848	$16,724,266
Capitalization and Liabilities		
Capitalization and Long-Term Liabilities		
Accumulated Net Revenues (Expenses)	**$691,226**	($1,906)
Federal Appropriations	**4,607,730**	4,596,506
Capitalization Adjustment	**2,090,903**	2,158,548
Long-Term Debt	**2,481,385**	2,663,141
Nonfederal Projects Debt	**6,024,866**	5,961,206
Decommissioning Reserve	**123,935**	73,726
Total capitalization and long-term liabilities	**16,020,045**	15,451,221
Current Liabilities		
Current portion of federal appropriations	**0**	46,687
Current portion of long-term debt	**384,700**	137,300
Current portion of nonfederal projects debt	**264,814**	243,366
Accounts payable and other current liabilities	**375,432**	364,144
Total current liabilities	**1,024,946**	791,497
Deferred Credits	**576,857**	481,548
	$17,621,848	$16,724,266

QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2004
Federal Columbia River Power System

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

	Six months ended March 31		Twelve months ended March 31	
	2004	2003	**2004**	2003
Operating Revenues				
Revenues	**$1,514,616**	$1,712,807	**$3,130,086**	$3,393,582
SFAS 133 mark-to-market (loss) gain	**28,413**	21,230	**62,448**	58,265
Other revenues	**27,598**	20,789	**60,487**	53,169
U.S. Treasury credits for fish	**36,504**	66,264	**145,124**	78,506
Total operating revenues	**1,607,131**	1,821,090	**3,398,145**	3,583,522
Operating Expenses				
Operations and maintenance	**511,472**	567,490	**1,142,503**	1,310,129
Purchased power	**291,557**	584,260	**750,306**	1,132,423
Non-Federal projects	**128,024**	112,993	**134,565**	172,406
Federal projects depreciation	**178,855**	173,721	**355,159**	348,003
Total operating expenses	**1,109,908**	1,438,464	**2,382,533**	2,962,961
Net operating revenues	**497,223**	382,626	**1,015,612**	620,561
Interest Expense				
Interest on federal investment				
Appropriated funds	**103,293**	109,010	**206,674**	242,465
Long-term debt	**62,342**	78,560	**150,380**	155,465
Allowance for funds used during construction	**(15,890)**	(14,714)	**(34,574)**	(60,089)
Net interest expense	**149,745**	172,856	**322,480**	337,841
Net Revenues	**$347,478**	$209,770	**$693,132**	$282,720

Derivative Instruments and Hedging Activities

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

Appendix C

REPORT OF INDEPENDENT ACCOUNTANTS

To the Executive Board of Energy Northwest:

We have audited the accompanying balance sheet of Energy Northwest and the related individual balance sheets of Energy Northwest's business units and internal service fund as of June 30, 2003, and the related statements of operations and cash flows for the year then ended. Energy Northwest's business units include the Columbia Generating Station, Packwood Lake Hydroelectric Project, Nuclear Project No. 1, Nuclear Project No. 3, the Business Development Fund, Gray's Harbor Energy Facility and the Nine Canyon Wind Project. These basic financial statements are the responsibility of Energy Northwest's management. Our responsibility is to express an opinion on these basic 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 audits to obtain reasonable assurance about whether the basic 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 basic financial statements referred to above present fairly, in all material respects, the financial position of Energy Northwest and Energy Northwest's business units and internal service fund as of June 30, 2003, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis (MD&A) listed in the table of contents is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. The information in MD&A has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we express no opinion on it.

PricewaterhouseCoopers LLP

Portland, Oregon September 5, 2003

MANAGEMENT'S DISCUSSION AND ANALYSIS

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington. Each Energy Northwest Business Unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by Business Unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the Fiscal Year ended June 30, 2003, with the basic financial statements for the Fiscal Year ended June 30, 2002. Energy Northwest has adopted accounting policies and principles that are in accordance with accounting principles generally accepted in the United States of America. Energy Northwest applies Generally Accepted Accounting Principles (GAAP) to the extent it does not conflict with Governmental Accounting Standards Board (GASB) standards (see Note B to financial statements).

The financial statements include the balance sheets, statements of operations and fund equity; statements of cash flows, schedules of outstanding long-term debt and debt service requirements, and notes to the financial statements for each of the Business Units. The balance sheet presents the financial position of each Business Unit based on an accrual cost basis. The balance sheets report information about construction work in progress, amount of resources and obligations, restricted accounts and due to/due from balances (see Note B to financial statements) that reflect what is owed by each Business Unit.

The statements of operations and fund equity report information relating to all expenses, revenues and equity that reflect the results of each Business Unit and its related activities over the course of the fiscal year. This information aids in benchmarking activities, conducting comparisons to evaluate progress, and whether the Business Unit has successfully recovered its costs.

The statements of cash flow reflect cash receipts and disbursements and net changes resulting from operating, financing and investment activities. The statements provide insight into what generates cash, where the cash comes from, and what it was used for.

The notes to the financial statements present disclosures that provide for a full understanding of the material presented in the financial statements. This includes but is not limited to, accounting policies, significant balances and activities, material risks, commitments and obligations and subsequent events, if applicable.

COLUMBIA GENERATING STATION

The Columbia Generating Station Nuclear Power Plant is owned by Energy Northwest and its Participants and operated by Energy Northwest. The Plant is a 1,153 megawatt boiling water nuclear power station located on the Department of Energy's Hanford Reservation north of Richland, Washington. Columbia produced 7,616 GWh of electricity in Fiscal Year 2003, as compared to 8,926 GWh of electricity in Fiscal Year 2002. This decline in generation is a result of three forced outages during Fiscal Year 2003 along with a scheduled refueling outage which currently occurs every two years.

BALANCE SHEET ANALYSIS - Columbia Generating Station has just completed its first 2-year refueling and maintenance outage in Fiscal Year 2003. Utility Plant in Service increased by $64,149,000 from $3,419,489,000 in Fiscal Year 2002 to $3,483,638,000 in Fiscal Year 2003. The increase includes capitalization of an asset retirement cost of $31,110,000 due to the adoption of Financial Accounting Standards Board Statement 143 (see Financials Note G). The remaining $33,039,000 increase is made up of the Independent Spent Fuel Storage Installation (ISFSI) Project, and upgrades to Columbia's Security and Chemical Injection Systems Construction Work in Progress decreased by $16,367,000 from $30,355,000 in Fiscal Year 2002 to $13,987,000 in Fiscal Year 2003, mainly due to the ISFSI Project along with heightened security improvements being put into service.

Costs in Excess of Billings has increased from $120.7 million in Fiscal Year 2002 to $325.8 million in Fiscal Year 2003. This is largely due to refunding current maturities while extending the overall maturities on the refunding debt. The lack of a need for funds to pay off current maturities results in a cost that exceed billings. In addition, the accumulated decommisioning and site restoration accrued costs are not currently billed to Bonneville Power Association (BPA). BPA holds and manages a trust fund for the purpose of funding decommisioning and site restoration (see Note B to the financials, Decommisioning and Site Restoration). The balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet.

The Restricted Assets Special Funds decreased from Fiscal Year 2002 to 2003 by $96,751,000. The variance increase of $13,389,000 is due to the fact that the 2003 Bond Issue established a Columbia Construction Fund to be used for future capital project costs. The decrease of $110,140,000 is due to the reclassification of Decommissioning and Site Restoration values to be presented in the Deferred Charges, Costs in excess of billings section of the Balance Sheet due to SFAS 143, "Accounting for Obligations Associated with Retirement of Long-Lived Assets" (see Note G). The Debt Service Funds variance of $84,232,000 from Fiscal Year 2002 to 2003 is attributed to Bond Fund Reserve free-ups. The variance of $21,443,000 in Current Assets is attributable to the fact that investment rates were down significantly from Fiscal Year 2002 to 2003.

STATEMENT OF OPERATIONS ANALYSIS - Columbia Generating Station is a net-billed Project. Energy Northwest recognizes revenues equal to expense for each period on net-billed projects. No net revenue or loss is recognized and no equity is accumulated. The following changes from Fiscal Year 2002 for Net Operating Revenues are: Operating Revenues needed to cover expenditures are up $32,952,000 from $406,995,000 in Fiscal Year 2002 to $439,947,000 in Fiscal Year 2003. Nuclear fuel expenditures are down, from $30,311,000 in Fiscal Year 2002 to $27,061,000 in Fiscal Year 2003, because of reduced generation in an outage year. Less generation in an outage year resulted in less Generation Taxes, down $961,000, from $3,198,000 in Fiscal Year 2002 to $2,237,000 in Fiscal Year 2003, and Spent Fuel Disposal fees reduction of $1,234,000 from $8,487,000 in Fiscal Year 2002 to $7,253,000 in Fiscal Year 2003. Operations and Maintenance expenditures were higher by $42,480,000, from $116,832,000 in Fiscal Year 2002 to $159,312,000 in Fiscal Year 2003. This is the result of a diesel generator and condenser leak unplanned outage along with the scheduled refueling and maintenance outage. Decommissioning expenses increased $10,098,000 in Fiscal Year 2003 primarily due to the adoption of Financial Accounting Standards Board Statement 143 for Asset Retirement Obligation. This statement calls for the obligation to be recorded at a rate depreciated over the life of the plant. The amount is a combination of probable cases for accomplishing the required retirement obligations and their associated probabilities. The amount will also be increased each year to account for the accretion value of the obligation. Past estimates were based on the funding statement methodology required under plant license. The amount calculated was then being costed over the life of the plant (see Note B to financial statements for further explanation).

Other Income and Expense changes are the net effects on Columbia Debt (see Note E to financial statements). Investment Income was adversely affected by historically low rates of return resulting in a decline of $4,789,243 from $11,540,483 in Fiscal Year 2002 to $6,751,239 in Fiscal Year 2003. Additionally, results of the Bond Refunding issues reduced interest expense by $2,098,215 from $115,110,462 in Fiscal Year 2002 to $113,002,247 in Fiscal Year 2003. Amortization of Bond Discount Expense and Amortization of Bond Refunding netted an increased expense of $180,063 as a result of the Bond Refunding issues.

PACKWOOD LAKE HYDROELECTRIC PROJECT

The Packwood Lake Hydroelectric Project is owned and operated by Energy Northwest. The Project consists of a dam at Packwood Lake and a powerhouse 1800 ft. below the dam that is located south of Packwood, Washington. Packwood produced 91.08 GWh of electricity in Fiscal Year 2003 versus 81.61 GWh in Fiscal Year 2002.

BALANCE SHEET ANALYSIS - Current Assets have increased $843,000 from $1,379,000 in Fiscal Year 2002 to $2,222,000 in Fiscal Year 2003, due to increased sales revenue from greater generation. As a result, Packwood accrued $830,000 in excess cash that is available to be returned to the Participants in October 2003.

STATEMENT OF OPERATIONS ANALYSIS - The agreement with Project Participants obligates them to pay annual costs and they receive excess revenues. Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized and no equity is accumulated. Revenues decreased because of the cost decreases detailed below. Operations and Maintenance along with Administrative and General expenditures decreased $282,000, from $1,368,000 in Fiscal Year 2002 to $1,086,000 in Fiscal Year 2003. This was due to unusually high costs in Fiscal Year 2002 caused by an extended outage and a transformer failure.

Investment Income increased due to the participants electing to leave $500,000 in excess cash from Fiscal Year 2002 to fund future re-licensing expenditures. Fiscal Year 2002 had $36,000 compared to $44,000 in Fiscal Year 2003, an $8,000 increase.

NUCLEAR PROJECT NO. 1

Nuclear Project No. 1, a 1,250 MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Project No. 1. In Fiscal Year 1999, the assets and liabilities of Hanford Generating Project were consolidated into Nuclear Project No. 1. The Hanford Generating Project site is being restored and all funding requirements are net-billed obligations of Nuclear Project No. 1. Energy Northwest wholly owns Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity on Nuclear Project No. 1.

BALANCE SHEET ANALYSIS - Under the debt optimization program, long-term debt was decreased by $124,988,000, from $2,081,189,000 in Fiscal Year 2002 to $1,956,201,000 in Fiscal Year 2003, due to principle payments and debt restructuring to take advantage of lower interest rates.

STATEMENT OF OPERATIONS ANALYSIS - Investment Income decreased $4,103,000, from $6,669,000 in Fiscal Year 2002 to $2,566,000 in Fiscal Year 2003, because of historically low rates of return. The average rate of return for Fiscal Year 2002 was 3.78 percent versus the Fiscal Year 2003 average rate of 2.94 percent.

NUCLEAR PROJECT NO. 3

Nuclear Project No. 3, a 1,240 MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Project No. 3. Energy Northwest is no longer responsible for any site restoration costs as they were transferred with the assets to the Satsop Redevelopment Project (see Note F). The last parcel of land was transferred during this period. The debt service related activities remain and are net-billed.

BALANCE SHEET ANALYSIS - Under the debt optimization program, long-term debt was decreased $55,590,000, from $1,817,152,000 in Fiscal Year 2002 to $1,761,562,000 in Fiscal Year 2003 due to principle payments and debt restructuring to take advantage of lower interest rates.

STATEMENT OF OPERATIONS ANALYSIS - Investment Income decreased $2,046,000 due to historically low rates of return, from $5,682,000 in Fiscal Year 2002 to $3,636,000 in Fiscal Year 2003. In addition, Plant Preservation and Termination costs increased $3,198,000 due to an IRS arbitrage penalty in Fiscal Year 2003 as compared to Fiscal Year 2002 rebate.

BUSINESS DEVELOPMENT FUND

The Business Development Fund (BDF) was created by Executive Board Resolution No. 1006 in April 1997, for the purpose of holding, administering, disbursing, and accounting for Energy Northwest costs and revenues generated from engaging in new energy business opportunities.

The BDF is managed as an enterprise fund. Three business sectors have been created within the fund: General Services, Generation, and Professional Services. Each sector may have one or more programs that are managed as a unique business activity. A fourth business sector, Business Unit Support, has been created to capture costs associated with developing programs.

STATEMENT OF OPERATIONS ANALYSIS - Operating Revenues in Fiscal Year 2003 totaled $11,163,000 as compared to Fiscal Year 2002 revenues of $6,808,000, an increase of $4,355,000. Energy Northwest has experienced significant growth in several of its business programs. Among the major business program contributors to this growth are: reactor outage services by $2,095,000, operations and maintenance services by $1,570,000, and environmental services by $291,000.

Net Revenues for the Fiscal Year 2003 showed a $683,000 loss as compared to approximately a $1,740,000 loss in Fiscal Year 2002.

Two of Energy Northwest's Research and Investigation business projects, Zintel Canyon Wind Project and Wind Mining, accounted for $366,000 in expenditures with no revenues. Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. With the growing interest in renewable energy sources, Energy Northwest is seeking to meet some of this demand with new wind generation projects. The Board of Directors approved an expansion of the Nine Canyon Wind Project as its next wind development site. In Fiscal Year 2003, $161,000 was expended to begin developing the Nine Canyon Phase II project. The Business Development Fund will be reimbursed from the project, upon commercial operation, for these development costs. In Fiscal Year 2003, Energy Northwest's Nine Canyon Wind Project Phase I was completed and upon commercial operation (September 25, 2002) the development costs totaling $693,000 were reimbursed to the Business Development Fund. In addition, the participants of the Nine Canyon Wind Project reimbursed the Business Development Fund $209,000 for Wind Mining expenditures. This represented 50 percent of all Wind Mining expenditures to date. These costs are for research and investigation of new potential wind sites and expenditures that cannot be directly attributable to any single wind project.

In addition to wind generation, Energy Northwest is working with Soil Search LLC, of Kennewick, Washington, to develop a full-scale biomass power demonstration unit at a dairy farm near Pasco, Washington. This unit is expected to demonstrate a newly developed bioreactor technology produced by Soil Search. This research and development effort may provide a quantum leap in methane production from dairy cow manure. In Fiscal Year 2003, approximately $370,000 was expended on developing this project.

In Fiscal Year 2003, $201,000 was spent on sales and marketing efforts and another additional $1,071,000 was spent on developing the organizational infrastructure to support the growing business. Total operating revenues increased 64 percent in Fiscal Year 2003.

The Business Development Fund receives contributions from the Internal Service Fund to cover cash needs during this startup period. They are not expected to be paid back and are shown as contributions.

GRAYS HARBOR ENERGY FACILITY

Becoming the operator of the Grays Harbor Energy Facility is a key component in Energy Northwest's strategic plan to eventually own and operate combined cycle gas turbine power plants. This contract will be the first step toward establishing a credible position in the Combustion Turbine power generation market. It will provide the basis for Energy Northwest to become a major supplier of Operations and Maintenance services to other public utilities in the Northwest and to become an owner of gas turbine generating facilities, as well.

STATEMENT OF OPERATIONS ANALYSIS - Non-Operating revenues were $5,259,000 and $1,479,000 for Fiscal Year 2002 and Fiscal Year 2003, respectively. This decrease of $3,780,000 is due to the sale of the site in Fiscal Year 2002.

On January 15, 2001, Energy Northwest entered into an agreement to sell the Grays Harbor Energy Facility site to the Duke Energy North America (DENA) affiliate, Duke Energy Grays Harbor, LLC (DEGH). Energy Northwest recognized a total of $5,000,000 for the sale of the site in Fiscal Year 2002. BPA was paid $2,137,000 due under the Hold Period and Option Development Agreements. Revenues in Fiscal Year 2003 were recorded for reimbursable costs and services provided to DENA.

The actual sale of the land and assets at the site in Grays Harbor County near Elma, Washington, has already been concluded successfully. This was to lead to the construction by DEGH of a 630 megawatt combined cycle 2-on-1 gas turbine power plant at the site to be on-line by late 2003. Energy Northwest was to become the operator of the Grays Harbor Energy Facility. Due to current market conditions, Duke Energy North America has temporarily suspended construction on the Grays Harbor Energy Facility. Energy Northwest and DENA have entered into a contract for site preservation services during this construction suspension time period.

DENA is determining the appropriate schedule for the project to resume.

NINE CANYON WIND PROJECT

The Nine Canyon Wind Project is owned and operated by Energy Northwest. The Project is located in the Horse Heaven Hills area southeast of Kennewick, Washington. Electricity generated by the Project is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by the Benton County Public Utility District. The total project will produce enough energy capacity for approximately 20,000 average homes.

Phase I of the project consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 megawatts of electricity, for a total wind farm capacity of 48 megawatts. Public Utility Districts in the Northwest, whose customers have expressed an interest in purchasing at least a portion of their electricity from green power sources, purchase the electricity from the Project. Each purchaser of Phase I has signed a 22-year power purchase agreement with Energy Northwest.

Phase II of the Project will consist of an additional 12 wind turbines with an aggregate generating capacity of approximately 15.6 megawatts. As were the Phase I turbines, the Phase II turbines will be manufactured by BONUS Energy A/S, and installed by Renewable Energy

Systems (USA), Inc. The engineer-procure-construct contract (EPC Contract) became effective as of May 2003. The first two units of Phase II were in operation by September 30, 2003. Phase II will commence full operation by December 31, 2003. Each purchaser of Phase II has signed a 20-year power purchase agreement with Energy Northwest.

BALANCE SHEET ANALYSIS - Long-term debt in the form of bonds was sold in the amount of $70,675,000 to finance Phase I and $21,720,000 for Phase II of the Project. Construction for Phase I has been completed and the Project was declared commercially operational on September 25, 2002. Construction work in progress for Phase II totaled $3,965,000 for Fiscal Year 2003.

STATEMENT OF OPERATIONS ANALYSIS - Operating Revenues in Fiscal Year 2003 totaled $3,464,000. The project received revenue from the billing of the project purchasers at a rate of $35.00 per MWh. Other contribution of funds include $230,000 from the Renewable Energy Production Incentive (REPI). REPI was created as part of the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under Section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities.

Operating Costs are expended for debt service and for operational and maintenance items. The agreement with project purchasers anticipates a loss in Fiscal Year 2004 with additional cash needs being paid from existing project reserve funds. The reserve funds were established so that participant payments could start at $35.00 per MWh and increase at 3 percent per year over 22 years. The payment stream and the REPI receipts are projected to cover the total costs over the entire time frame.

INTERNAL SERVICE FUND

The Internal Service Fund (ISF) (formerly the General Fund) was established in May 1957. The Internal Service Fund provides services to the other funds. This Fund accounts for the central procurement of certain common goods and services for the business units on a cost reimbursement basis (see Note A and Note B to financial statements). This Fund accounts for the performance fees paid by BPA to Energy Northwest for achieving performance goals related to the operation of Columbia Generating Station.

BALANCE SHEET ANALYSIS

Restricted investments and cash and available for sale securities decreased $24.194 million from $27.103 million in Fiscal Year 2002 to $2.909 million in Fiscal Year 2003, due to the release of the majority of the Unclaimed Bond Fund and associated liability to Bonneville Power Administration (BPA). The majority of variance, $22.8 million is due to the disbursement of funds as per terms of the settlement and Indemnification Agreement between BPA and Energy Northwest (BPA Contract No. 03PB-11322).

STATEMENT OF OPERATIONS ANALYSIS

Net Revenues for Fiscal Year 2003 were $434,000 versus $5,810,000 for Fiscal Year 2002. The main contributor to this variance of $5,376,000 is the suspension of the Performance Fee award program by BPA in 2003.

BALANCE SHEETS
As of June 30, 2003 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO. 1 *	NUCLEAR PROJECT NO. 3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2003 COMBINED TOTAL
ASSETS										
UTILITY PLANT (NOTE B)										
In service	$ 3,483,638	$ 12,991	$ —	$ —	$ 823	$ —	$ 48,478	$ 3,545,930	$ 43,837	$ 3,589,767
Accumulated depreciation	(1,874,957)	(12,083)			(214)		(1,630)	(1,888,884)	(29,124)	(1,918,008)
	1,608,681	908	—	—	609	—	46,848	1,657,046	14,713	1,671,759
Nuclear fuel, net of accumulated amortization	121,275							121,275		121,275
Construction work in progress	13,987						3,965	17,952		17,952
	1,743,943	908	—	—	609	—	50,813	1,796,273	14,713	1,810,986
RESTRICTED ASSETS (NOTE B)										
Special funds										
Cash	10		21	3			23	57	1,599	1,656
Available-for-sale investments	31,541	284	19,917	13,407			18,083	83,232	1,310	84,542
Accounts and other receivables			4,178				17	4,195		4,195
Prepayments and other			25					25	274	299
Due from other business units			2,129					2,129		
Debt service funds										
Cash	57,877	2	32,987	27,324			6,053	124,243		124,243
Available-for-sale investments	4,900	743	17,602	23,498			1,325	48,068		48,068
Due from other funds	4,099		4,324	211				8,634		
Other receivables			10					10		10
	98,427	1,029	81,193	64,443	—	—	25,501	270,593	3,183	263,013
LONG-TERM RECEIVABLES (NOTE B)	6,591							6,591		6,591
CURRENT ASSETS										
Cash	1,915	4	544	239		5	3	2,710		2,710
Available-for-sale investments	1,658	1,770	16,085	5,761	895	2,209	5,734	34,112	24,604	58,716
Accounts and other receivables	989	374	8		978	561	238	3,148	123	3,271
Due from Participants	841		12	9				862		862
Due from other business units	226		708	2,095	1,542	44	342	4,957	8,813	
Due from other funds	12,750	7	3,072	9,381			90	25,300		
Materials and supplies	70,739							70,739		70,739
Prepayments and other	628	67			51			746	166	912
Nuclear fuel held for sale			4,345					4,345		4,345
Plant & equipment held for sale			1,409					1,409		1,409
	89,746	2,222	26,183	17,485	3,466	2,819	6,407	148,328	33,706	142,964
DEFERRED CHARGES										
Costs in excess of billings	325,818	2,097	1,921,575	1,701,508				3,950,998		3,950,998
Unamortized debt expense	15,271	2	16,531	13,194			4,286	49,284		49,284
Other deferred charges	1						5,110	5,111		5,111
	341,090	2,099	1,938,106	1,714,702	-	—	9,396	4,005,393	—	4,005,393
TOTAL ASSETS	$ 2,279,797	$ 6,258	$ 2,045,482	$ 1,796,630	$ 4,075	$ 2,819	$ 92,117	$ 6,227,178	$ 51,602	$ 6,228,947

** Project recorded on a liquidation basis*
See notes to financial statements

BALANCE SHEETS (continued)

As of June 30, 2003 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO. 1 *	NUCLEAR PROJECT NO. 3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2003 COMBINED TOTAL
FUND EQUITY AND LIABILITIES										
FUND EQUITY (DEFICIT)	$ —	$ —	$ —	$ —	$ 2,776	$ 1,848	$ (2,261)	$ 2,363	$ 4,121	$ 6,484
LONG-TERM DEBT (NOTE E)										
Revenue bonds payable	2,019,765	3,939	1,980,615	1,938,515			92,395	6,035,229		6,035,229
Unamortized discount on bonds - net	32,054	(8)	50,054	(142,111)			730	(59,281)		(59,281)
Unamortized gain/(loss) on bond refundings	(49,023)	33	(74,468)	(34,842)				(158,300)		(158,300)
	2,002,796	3,964	1,956,201	1,761,562	—	—	93,125	5,817,648	—	5,817,648
LIABILITIES - PAYABLE FROM RESTRICTED ASSETS (NOTE B)										
Special funds										
Accounts payable and accrued expenses	48,265		36,970				467	85,702	2,295	87,997
Due to other funds	16,849	4	7,395	9,592			90	33,930		
Other deferred credits					185			185		185
Debt service funds										
Accrued interest payable	16,451	53	42,875	23,396			147	82,922		82,922
Due to other funds		3						3		
	81,565	60	87,240	32,988	185	—	704	202,742	2,295	171,104
OTHER NONCURRENT LIABILITIES	30,701							30,701		30,701
CURRENT LIABILITIES										
Cash Overdrafts					2			2	537	539
Current maturities of long-term debt	129,030	377								
Accounts payable and accrued expenses								129,407		129,407
Due to Participants	19,746	57		368	886	17	436	21,510	41,314	62,824
Due to other business units	4,125	1,330	2,032	804				8,291		8,291
	11,834	470	9	908	226	127	113	13,687	2,213	
	164,735	2,234	2,041	2,080	1,114	144	549	172,897	44,064	201,061
DEFERRED CREDITS										
Advances from Members and others						827		827	1	828
Other deferred credits									1,121	1,121
	—	—	—	—	—	827	—	827	1,122	1,949
TOTAL LIABILITIES	2,279,797	6,258	2,045,482	1,796,630	1,299	971	94,378	6,224,815	47,481	6,222,463
TOTAL FUND EQUITY (DEFICIT) AND LIABILITIES	$ 2,279,797	$ 6,258	$ 2,045,482	$ 1,796,630	$ 4,075	$ 2,819	$ 92,117	$ 6,227,178	$ 51,602	$ 6,228,947

** Project recorded on a liquidation basis*

See notes to financial statements

STATEMENTS OF OPERATIONS AND FUND EQUITY

For the year ended June 30, 2003 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO. 1 *	NUCLEAR PROJECT NO. 3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2003 COMBINED TOTAL
OPERATING REVENUES	$ 439,947	$ 1,596	$ —	$ —	$ 11,163	$ —	$ 3,464	$ 456,170	$ 68,491	$ 456,604
OPERATING EXPENSES										
Services to other business units									66,552	
Nuclear fuel	27,061							27,061		27,061
Spent fuel disposal fee	7,253							7,253		7,253
Decommissioning	26,505							26,505		26,505
Depreciation and amortization	79,528	365			158		1,834	81,885	1,533	81,885
Operations and maintenance	159,312	922					1,068	161,302		161,302
Administrative & general	26,901	164					33	27,098		27,098
Generation tax	2,237	19					22	2,278		2,278
New business initiatives					11,276			11,276		11,276
Total operating expenses	328,797	1,470	—	—	11,434	—	2,957	344,658	68,085	344,658
NET OPERATING REVENUES (EXPENSES)	111,150	126			(271)		507	111,512	406	111,946
OTHER INCOME & EXPENSE										
Non-operating revenues			138,301	95,718		1,479		235,498		235,498
Investment income	6,751	44	2,566	3,636	36	19	269	13,321	61	13,321
Gain/(loss) on current bond redemption		4								4
Interest expense and								4		
discount amortization	(119,666)	(174)	(111,279)	(96,223)			(3,154)	(330,496)		(330,496)
Plant preservation and termination costs			(4,817)	(3,131)				(7,948)		(7,948)
Depreciation and amortization			(26)			(19)		(45)		(45)
Revaluation of Site Restoration**			(24,984)					(24,984)		(24,984)
Other	1,765		239		(448)	(1,247)			(33)	309
NET REVENUES (EXPENSES)	—	—	—	—	(683)	232	(2,378)	(2,829)	434	(2,395)
Distribution & Contributions	—	—	—	—	2,048	—	230	2,278	(1,436)	842
Beginning Fund Equity (DEFICIT)	—	—	—	—	1,411	1,616	(113)	2,914	5,123	8,037
ENDING FUND EQUITY (DEFICIT)	$ —	$ —	$ —	$ —	$ 2,776	$ 1,848	$ (2,261)	$ 2,363	$ 4,121	$ 6,484

** Project recorded on a liquidation basis*
***See Note G (SFAS 143)*
See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 2003 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	INTERNAL SERVICE FUND	2003 COMBINED TOTAL
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES									
Operating revenue receipts	$ 247,421	$ 3,498	$ —	$ —	$ 5,231	$ —	$ 3,445	$ —	$ 259,595
Cash payments for operating expenses	(192,106)	(1,599)					(1,086)		(194,791)
Non-operating revenue receipts			76,785	72,908		1,784		(21,352)	130,125
Cash payments for preservation, termination expense			(54,453)	(42,114)					(96,567)
Cash payments for new business					(4,580)				(4,580)
Net cash provided (used) by operating and other activities	55,315	1,899	22,332	30,794	651	1,784	2,359	(21,352)	93,782
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES									
Proceeds from bond refundings	224,442		487,956	591,604			22,448		1,326,450
Refunded bond escrow requirement	(179,350)		(489,845)	(592,889)					(1,262,084)
Payment for bond issuance and financing costs	(2,380)		(4,149)	(5,137)			(898)		(12,564)
Capital and nuclear fuel acquisitions	(55,264)								(55,264)
Interest paid on revenue bonds	(82,457)	(177)	(151,537)	(152,240)			(3,940)		(390,351)
Principal paid on revenue bond maturities	(21,310)	(532)	(86,116)	(5,870)					(113,828)
Interest paid on Notes	(1,613)		(241)	(418)					(2,272)
Notes Payable	(34,518)								(34,518)
Construction Work in Progress							(18,008)		(18,008)
Net cash provided (used) by capital and related financing activities	(152,450)	(709)	(243,932)	(164,950)	—	—	(398)	—	(562,439)
CASH FLOWS FROM INVESTING ACTIVITIES									
Purchases of investment securities	(1,323,070)	(10,384)	(899,670)	(624,780)	(21,867)	(13,304)	(84,712)	(256,212)	(3,233,999)
Sales of investment securities	1,448,204	9,147	1,130,580	764,522	21,146	11,504	88,356	246,602	3,720,061
Interest on investments	6,275	41	15,773	6,084	36	20	472	1,203	29,904
Receipts from sales of plant assets			6						6
Net cash provided (used) by investing activities	131,409	(1,196)	246,689	145,826	(685)	(1,780)	4,116	(8,407)	515,972
NET INCREASE (DECREASE) IN CASH	34,274	(6)	25,089	11,670	(34)	4	6,077	(29,759)	47,315
CASH AT JUNE 30, 2002	25,528	12	8,463	15,896	32	1	2	30,821**	80,755
CASH AT JUNE 30, 2003 (NOTE B)	$ 59,802	$ 6	$ 33,552	$ 27,566	$ (2)	$ 5	$ 6,079	$ 1,062	$ 128,070

** Project recorded on a liquidation basis*
*** Reclassification of short term investments in FY02*
See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 2003 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO. 1 *	NUCLEAR PROJECT NO. 3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR NINE ENERGY FACILITY	NINE CANYON WIND PROJECT	INTERNAL SERVICE FUND	2003 COMBINED TOTAL
RECONCILIATION OF OPERATING INCOME TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES									
Net operating revenues	$ 111,150	$ 126	$ —	$ —	$ (271)	$ —	507	$ —	$ 111,512
Adjustments to reconcile net operating revenues to cash provided by operating activities:									
Cost/cash incurred in excess of cash/cost	(199,001)	(361)							(199,362)
Depreciation and amortization	105,474	362			48		1,800		107,684
Decommissioning	26,505						26		26,531
Other	(723)				(448)				(1,171)
Change in operating assets and liabilities:									
Accounts receivable	4,105	281			(524)		(8)		3,854
Materials and supplies	1,807								1,807
Prepaid and other assets	(369)	(67)			(42)				(478)
Due from/to other business units, funds and Participants	(1,409)	1,564			(1,001)		(2)		(848)
Accounts payable	7,776	(6)			2,889		36		10,695
Non-operating revenue receipts			76,785	72,908		595			150,288
Cash payments for preservation, termination expense			(54,453)	(42,114)					
Cash payments for services									(96,567)
Cash payments for new business						1,189		(21,352)	(20,163)
Net cash provided (used) by operating and other activities	$ 55,315	$ 1,899	$ 22,332	$ 30,794	$ 651	$ 1,784	$ 2,359	$ (21,352)	$ 93,782

* Project recorded on a liquidation basis

See notes to financial statements

OUTSTANDING LONG-TERM DEBT
As of June 30, 2003 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
COLUMBIA (NUCLEAR PROJECT NO. 2) REFUNDING REVENUE BONDS				
1990A	7.25%	7-1-2006	$ 2,115	
			2,115	
1990C	(C)	7-1-2004/2005	18,054	
			18,054	
1991A	(C)	7-1-2006/2007	10,267	
			10,267	
1992A	5.90-6.10	7-1-2004/2006	12,415	
	6.30	7-1-2012	50,000	
			62,415	
1993A	5.50-5.80	7-1-2004/2008	65,350	
			65,350	
1993B	5.40-5.65	7-1-2005/2008	54,725	
			54,725	
1994A	4.80-6.00	7-1-2004/2011	495,695	
	(C)	7-1-2009	4,776	
	5.40	7-1-2012	100,200	
			600,671	
1996A	5.50-6.00	7-1-2004/2012	195,385	
			195,385	
1997A	5.10-5.20	7-1-2010/2012	50,355	
			50,355	
1997B	5.00-5.50	7-1-2004/2011	30,000	
			30,000	
1998A	5.00-5.75	7-1-2004/2012	181,285	
			181,285	
2001A	5.00-5.50	7-1-2013/2017	186,600	
			186,600	
2001B	5.50	7-1-2018	48,000	
			48,000	
2002A	5.20-5.75	7-1-2017/2018	157,260	
			157,260	
2002B	5.35-6.00	7-1-2018	123,815	
			123,815	
2003A	5.50	7-1-2010/2015	154,490	
			154,490	
2003B	4.15	7-1-2009	4,530	
			4,530	
2003F	5.00-5.25	7-1-2007/2018	41,330	
			41,330	
1997-2A-1	Average Variable 1.2%		51,195	
			51,195	
1997-2A-2	Average Variable 1.2%		51,190	
			51,190	
Compound interest bonds accretion			59,763	
Revenue bonds payable			2,148,795	(B)
Estimated fair value at June 30, 2003			$2,384,394	(D)

(A) Includes amounts due July 1, 2003.
(B) Excludes amounts due July 1, 2003, which were paid as of June 30, 2003.
(C) Compound Interest Bonds.
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(E) Auction Rate Certificates that will have a rate of 5.50 through 7/1/2009, and a variable rate thereafter until 7/1/2018.

OUTSTANDING LONG-TERM DEBT (continued)
As of June 30, 2003 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
PACKWOOD LAKE PROJECT REVENUE BONDS				
1962	3.625%	3-1-2012	$ 3,191	
			3,191	
1965	3.75	3-1-2012	1,125	
			1,125	
Revenue bonds payable			$ 4,316	(B)
Estimated fair value at June 30, 2003			$ 4,533	(D)
NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS				
1989B	7.125	7-1-2016	$ 41,070	
			41,070	
1990B	7.25	7-1-2009	3,590	
			3,590	
1992A	5.90-6.10	7-1-2004/2006	1,360	
			1,360	
1993A	5.30-7.00	7-1-2004/2009	51,330	
			51,330	
1993B	5.10-7.00	7-1-2004/2009	37,890	
			37,890	
1993C	4.90-5.20	7-1-2004/2008	9,015	
			9,015	
1996A	5.50-6.00	7-1-2004/2012	337,790	
			337,790	
1996B	5.10-7.00	7-1-2004/2005	19,950	
			19,950	
1996C	5.00-6.00	7-1-2004/2015	71,690	
	5.50	7-1-2017	24,860	
			96,550	
1997A	6.00	7-1-2006/2008	20,400	
			20,400	
1997B	5.00-5.125	7-1-2004/2017	244,375	
			244,375	
1998A	5.00-5.75	7-1-2004/2017	85,290	
			85,290	
2001A	4.125-5.50	7-1-2004/2013	82,760	
			82,760	
2001B	5.50	7-1-2017	23,600	(E)
			23,600	

(A) Includes amounts due July 1, 2003.
(B) Excludes amounts due July 1, 2003, which were paid as of June 30, 2003.
(C) Compound Interest Bonds.
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(E) Auction Rate Certificates that will have a rate of 5.50 through 7/1/2009 and a variable rate thereafter until 7/1/2018.

OUTSTANDING LONG-TERM DEBT (continued)
As of June 30, 2003 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS (Continued)				
2002A	5.5-5.75	7-1-2013/2017	$ 248,485	
			248,485	
2002B	6.00	7-1-2017	101,950	
			101,950	
2003A	5.50	7-1-2013/2017	241,455	
			241,455	
2003B	4.06	7-1-2009	18,210	
			18,210	
1993-1A-1	Average Variable 1.1%		49,430	
			49,430	
1993-1A-2	Average Variable 1.1%		49,430	
			49,430	
1993-1A-3	Average Variable 1.1%		16,200	
			16,200	
2003C	Average Variable 1.1%		200,485	
			200,485	
Revenue bonds payable			$ 1,980,615	(A)
Estimated fair value at June 30, 2003			$ 2,222,053	(D)

(A) Includes amounts due July 1, 2003.
(B) Excludes amounts due July 1, 2003, which were paid as of June 30, 2003.
(C) Compound Interest Bonds.
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(E) Auction Rate Certificates that will have a rate of 5.50 through 7/1/2009 and a variable rate thereafter until 7/1/2018.

OUTSTANDING LONG-TERM DEBT (continued)

As of June 30, 2003 (Dollars in Thousands)

SERIES	COUPON RATE	OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO. 3 REFUNDING REVENUE BONDS				
1989A	(C)	7-1-2004/2014	$ 17,107	
			17,107	
1989B	(C)	7-1-2004/2014	70,580	
	7.125	7-1-2016	76,145	
			146,725	
1990B	(C)	7-1-2004/2010	23,636	
			23,636	
1993B	5.10-7.00	7-1-2004/2009	63,090	
			63,090	
1993C	4.90-7.50	7-1-2004/2008	80,720	
	(C)	7-1-2013/2018	23,963	
			104,683	
1996A	5.50-6.00	7-1-2004/2009	30,735	
			30,735	
1997A	5.00-6.00	7-1-2004/2018	107,695	
			107,695	
1998A	5.00	7-1-2004/2005	16,675	
	5.125	7-1-2018	53,825	
			70,500	
2001A	5.00-5.50	7-1-2004/2018	170,010	
			170,010	
2001B	5.00-5.50	7-1-2018	25,675	(E)
			25,675	
2002B	6.00	7-1-2016	75,360	
			75,360	
2003A	5.50	7-1-2011/2017	241,915	
			241,915	
2002B	4.15	7-1-2009	21,575	
			21,575	
1993-3A-3	Average Variable 1.2%		22,255	
			22,255	
1998-3A	Average Variable 1.2%		144,330	
			144,330	
2003D	Average Variable 1.2%		201,065	
			201,065	
2003E	Average Variable 1.2%		98,025	
			98,025	
Compound interest bonds accretion			374,134	
Revenue bonds payable			$ 1,938,515	(A)
Estimated fair value at June 30, 2003			$ 1,989,747	(D)

(A) Includes amounts due July 1, 2003.
(B) Excludes amounts due July 1, 2003, which were paid as of June 30, 2003.
(C) Compound Interest Bonds.
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(E)Auction Rate Certificates that will have a rate of 5.50 through 7/1/2009 and a variable rate thereafter until 7/1/2018.

OUTSTANDING LONG-TERM DEBT (continued)

As of June 30, 2003 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NINE CANYON WIND PROJECT REVENUE BONDS				
2001A	4.00-6.00	7-1-2004/2023	$ 50,410	
			50,410	
2001B	4.30-6.00	7-1-2017	20,265	
			20,265	
2003	3.00-5.00	7-1-2005/2023	21,720	
			21,720	
Revenue bonds payable			$ 92,395	(B)
Estimated fair value at June 30, 2003			$ 104,319	(D)

(A) Includes amounts due July 1, 2003.
(B) Excludes amounts due July 1, 2003, which were paid as of June 30, 2003.
(C) Compound Interest Bonds.
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(E)Auction Rate Certificates that will have a rate of 5.50 through 7/1/2009 and a variable rate thereafter until 7/1/2018.

DEBT SERVICE REQUIREMENTS
As of June 30, 2003 (Dollars in Thousands)

COLUMBIA GENERATING STATION

FISCAL YEAR		PRINCIPAL		INTEREST		TOTAL
6/30/2003						
Balance*:	$	-	$	16,451	$	16,451
2004		123,424		121,823		245,247
2005		101,885		127,770		229,655
2006		94,046		111,783		205,829
2007		151,996		101,243		253,239
2008		146,665		86,448		233,113
2009-2013		887,621		303,787		1,191,408
2014-2018		583,395		125,574		708,969
Adjustment **		59,763		(59,763)		-
	$	2,148,795	$	935,116	$	3,083,911

* Principal and interest due July 1, 2003.
** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet.

PACKWOOD LAKE HYDROELECTRIC PROJECT

FISCAL YEAR		PRINCIPAL		INTEREST		TOTAL
6/30/2003						
Balance:*	$	188	$	53	$	241
2004		574		151		725
2005		598		130		728
2006		624		108		732
2007		648		85		733
2008		673		63		736
2009-2012		1,011		59		1,070
	$	4,316	$	649	$	4,965

* Principal and interest due July 1, 2003.

DEBT SERVICE REQUIREMENTS (continued)

As of June 30, 2003 (Dollars in Thousands)

NUCLEAR PROJECT NO. 1

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2003 Balance:*	$ -	$ 42,875	$ 42,875
2004	66,910	103,785	170,695
2005	56,510	100,144	156,654
2006	77,890	97,030	174,920
2007	64,575	92,625	157,200
2008	79,000	88,954	167,954
2009-2013	540,290	374,678	914,968
2014-2017	1,095,440	156,704	1,252,144
2018			
	$ 1,980,615	$ 1,056,795	$ 3,037,410

* Principal and interest due July 1, 2003.

NUCLEAR PROJECT NO. 3

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2003 Balance:*	$ -	$ 23,396	$ 23,396
2004	62,906	96,156	159,062
2005	64,471	94,872	159,343
2006	65,392	93,377	158,769
2007	60,176	93,845	154,021
2008	63,330	90,853	154,183
2009-2013	352,241	411,430	763,671
2014-2018	895,865	236,003	1,131,868
Adjustment **	374,134	(374,134)	
	$ 1,938,515	$ 765,798	$ 2,704,313

* Principal and interest due July 1, 2003.
** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet.

DEBT SERVICE REQUIREMENTS (continued)
As of June 30, 2003 (Dollars in Thousands)

NINE CANYON WIND PROJECT

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2003	$ -	$ 147	$ 147
Balance:*			
2004	2,060	5,066	7,126
2005	2,915	4,835	7,750
2006	3,040	4,720	7,760
2007	3,170	4,594	7,764
2008	3,315	4,457	7,772
2009-2013	19,280	19,689	38,969
2014-2018	25,175	13,999	39,174
2019-2023	33,440	5,994	39,434
	$ 92,395	$ 63,501	$ 155,896

* Principal and interest due July 1, 2003.

NOTES TO FINANCIAL STATEMENTS

NOTE A – GENERAL

Organization

Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, was organized in 1957. It is empowered to finance, acquire, construct, and operate facilities for the generation and transmission of electric power. On June 30, 2003, its membership consisted of 15 public utility districts and three cities, Richland, Seattle, and Tacoma. All members own and operate electric systems within the State of Washington. Energy Northwest is exempt from federal income tax. Energy Northwest has no taxing authority.

Energy Northwest Business Units

Energy Northwest operates Columbia Generating Station, a 1,153 MWe (Design Electric Rating, net) generating plant completed in 1984. Energy Northwest has obtained all permits and licenses required to operate Columbia, including a Nuclear Regulatory Commission (NRC) operating license that expires in December 2023.

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5 MWe generating plant completed in 1964. Packwood operates under a fifty-year license from the Federal Energy Regulatory Commission (FERC) that expires on February 28, 2010. The electric power produced by Packwood is sold to 12 utilities, which pay the costs of Packwood, including the debt service on the Packwood Hydroelectric review bonds. The Packwood Participants are obligated to pay annual costs of the Project including debt service, whether or not the Project is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of the bond resolution. The Participants share project revenue as well.

Nuclear Project No. 1, a 1,250 MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. Nuclear Project No.3, a 1,240 MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3 (see Note F – Nuclear Projects Nos. 1 and 3 Termination). In fiscal year 1999, the assets and liabilities of Hanford Generating Project were consolidated into Nuclear Project No. 1. The Hanford Generating Project site is being restored and all funding requirements are net-billed obligations of Nuclear Project No. 1. Nuclear Project No. 1 is wholly owned by Energy Northwest.

Each Energy Northwest Business Unit is financed and accounted for separately from all other current or future Business Units.

All electrical energy produced by Energy Northwest net-billed Business Units is ultimately delivered to electrical distribution facilities owned and operated by BPA as part of the Federal Columbia River Power System. BPA in turn distributes the electricity to electric utility systems throughout the Northwest, including Participants in Energy Northwest's Business Units, for ultimate distribution to consumers. Participants in Energy Northwest's net-billed Business Units consist of publicly owned utilities and rural electric cooperatives located in the western United States that have entered into net-billing agreements with Energy Northwest and BPA for participation in one or more of Energy Northwest's Business Units. BPA is obligated by law to establish rates for electric power which will recover the cost of electric energy acquired from Energy Northwest and other sources as well as BPA's other costs (See Note E).

Energy Northwest also manages the Business Development Fund, Nine Canyon Wind Project, and Grays Harbor Energy Facility Project. The Business Development Fund was established in April 1997, to pursue and develop new energy-related business opportunities. The Nine Canyon Wind Project was established in January 2001, for the purpose of exploring and establishing a wind energy Project. Phase I of the project was completed in fiscal year 2003. Phase I of the Project consists of turbines which are rated at 48 MWe. Phase II of the project has been approved and construction is expected to be complete by December 31, 2003. Phase II of the Project will consist of turbines which are rated 15.6 MWe.

The Grays Harbor Energy Facility Project was established in July 1990, to collect advances and contributions to pay the costs of investigating new generating Projects, including the feasibility of a combustion turbine near Satsop, Washington. The Project purpose was amended during Fiscal Year 2002 to include the operation and maintenance of a gas fired combustion turbine placed on the Grays Harbor site (owned by Duke Energy Grays Harbor LLC) and included the option to purchase up to 50 MW of power generated by the facility. Due to current market conditions, Duke Energy North America has temporarily suspended construction of the combustion turbine plant.

The Internal Service Fund (formerly General Fund) was established in May 1957. It is currently used to account for the central procurement of certain common goods and services for the Business Units on a cost reimbursement basis. It is also used to account for the performance fees to Energy Northwest for achieving performance goals related to the operation of the projects.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Energy Northwest has adopted accounting policies and principles that are in accordance with accounting principles generally accepted in the United States of America. Accounts are maintained in accordance with the uniform system of accounts of the Federal Energy Regulatory Commission (FERC). Separate funds and books of account are maintained for each Business Unit. Payment of obligations of one Business Unit with funds of another Business Unit is prohibited, and would constitute violation of bond resolution covenants.

Energy Northwest maintains an Internal Service Fund for centralized control and accounting of certain fixed assets such as data processing equipment, and for payment and accounting of internal services, payrolls, benefits, administrative and general expenses, and certain contracted services on a cost reimbursement basis. In addition, it is used to account for performance fees including those paid to Energy Northwest for achieving performance goals related to the operation of the Projects. Certain assets in the Internal Service Fund are also owned by the Fund and operated for the benefit of other Projects. Depreciation relating to fixed assets is charged to the appropriate Business Units based upon direct labor costed to each Project.

Liabilities of the Internal Service Fund represent accrued payrolls, vacation pay, employee benefits, and common accounts payable which have been charged directly or indirectly to Business Units and will be funded by the Business Units when paid. Net amounts owed to or receivable from Energy Northwest Business Units are recorded under Current Liabilities - Due to other Business Units, or Current Assets - Due from other Business Units on the Internal Service Fund balance sheet.

The Combined Total column on the financial statements is for presentation only as each Energy Northwest Business Unit is financed and accounted for separately, from all other current and future Business Units. The FY2003 Combined Total includes eliminations for transactions between Business Units as required in Statement No. 34, "Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments" of the Governmental Accounting Standards Board (GASB).

Pursuant to Statement No. 20 of the Governmental Accounting Standards Board (GASB), "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," Energy Northwest has elected to apply all Financial Accounting Standards Board statements and interpretations, except for those that conflict with or contradict GASB pronouncements. Specifically, Statement of Governmental Accounting Standard No. 7, "Advance Refundings Resulting in Defeasance of Debt" and No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities" conflict with Statement of Financial Accounting Standards (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." As such, the guidance under Statement of Governmental Accounting Standard No. 7 and No. 23 is followed. Such guidance governs the accounting for bond defeasances and refundings.

The preparation of Energy Northwest financial statements in conformity with accounting principles generally accepted in the United States of America necessarily requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Certain incurred expenses and revenues are allocated to the Business Units based on specific allocation methods and management considers the allocation methods to be reasonable.

Energy Northwest's fiscal year begins on July 1st and ends on June 30th.

Utility Plant

Utility plant is stated at original cost. Plant in service is depreciated by the straight-line method over the estimated useful lives of the various classes of plant, which range from five to 60 years. The Nuclear Regulatory Commission now grants license extensions. Energy Northwest plans to file and receive extensions. This practice has been acknowledged and accepted by utilities abroad. In prior years, Energy Northwest had calculations for certain long lived assets based on a 40-year useful life. As of July 1, 2002, Energy Northwest is changing the depreciation schedules to reflect a 60-year useful life. This results in a decrease in depreciation expense of approximately $16 million in Fiscal Year 2003. In addition, the year to year depreciation expense effect is approximately $16 million per year. The depreciation schedule will reflect this change in Fiscal Year 2003 and prospectively.

During the normal construction phase of a Project, Energy Northwest's policy is to capitalize all costs relating to the Project, including interest expense (net of interest income), and related administrative and general expense.

The utility plant and net assets of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in fiscal year 1995 and is included in Cost in Excess of Billings. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 1 and 3 have been charged to operations. Utility Plant activity for the year ended June 30, 2003, was as follows:

UTILITY PLANT ACTIVITY *(Amount in Thousands)*

	BEGINNING BALANCE	INCREASES	DECREASES	ENDING BALANCE
Columbia				
Generation	$ 3,419,489	$ 33,039	$ -	$ 3,452,528
Decommission	-	31,110	-	31,110
Construction Work in Progress	30,355	-	(16,368)	13,987
Accumulated Depreciation	(1,786,935)	(78,161)	-	(1,865,096)
Accumulated Amortization	-	(9,861)	-	(9,861)
Utility Plant, net	$ 1,662,909	$ (23,873)	$ (16,368)	$ 1,622,668
Nine Canyon				
Generation	$ -	$ 48,029	$ -	$ 48,029
Decommission	-	449	-	449
Construction Work in Progress	48,387	-	(44,422)	3,965
Accumulated Depreciation	-	(1,622)	-	(1,622)
Accumulated Amortization	-	(8)	-	(8)
Utility Plant, net	$ 48,387	$ 46,848	$ (44,422)	$ 50,813
Packwood				
Generation	$ 12,855	$ 137	$ -	$ 12,991
Accumulated Depreciation	(11,722)	(362)	-	(12,084)
Utility Plant, net	$ 1,133	$ (225)	$ -	$ 908
Business Development				
General	$ 757	$ 66	$ -	$ 823
Accumulated Depreciation	(166)	(48)	-	(214)
Utility Plant, net	$ 591	$ 18	$ -	$ 609
Internal Service Fund				
General	$ 43,547	$ 290	$ -	$ 43,837
Accumulated Depreciation	(27,591)	(1,533)	-	(29,124)
Utility Plant, net	$ 15,956	$ (1,243)	$ -	$ 14,713

Nuclear Fuel

All expenditures related to the purchase of nuclear fuel for Columbia, including interest, are capitalized and carried at cost. When the fuel is placed in the reactor, the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. Accumulated nuclear fuel amortization (the amortization of the cost of nuclear fuel assemblies in the reactor used in the production of energy and in the fuel pool for less than six months per FERC guidelines) is $103 million as of June 30, 2003, for Columbia.

Energy Northwest has a contract with the Department of Energy (DOE) that requires the DOE to accept title and dispose of spent nuclear fuel. Although the courts have ruled that the DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, the repository is not expected to be in operation before 2010. The current period operating expense for Columbia includes a $7.2 million charge for future spent nuclear fuel storage and disposal to be provided by the DOE in accordance with the Nuclear Waste Policy Act of 1982.

Energy Northwest has completed a Project to store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. Spent Fuel will be transferred from the Spent Fuel pool to the Independent Spent Fuel Storage Installation periodically to allow for future refuelings. Current period operating costs include $23.5 million for nuclear fuel and $3.6 million accrued dry cask storage costs. $2.1 million of the $3.6 million of accrued dry cask storage costs is related to an increase in the estimate of dry cask storage costs. The remaining $1.5 million is directly related to amortization.

Restricted Assets

In accordance with Project bond resolutions, related agreements or state law, separate restricted funds have been established for each Business Unit. The assets held in these funds are restricted for specific uses including construction, debt service, capital additions, extraordinary operations and maintenance costs, termination, decommissioning, and workers' compensation claims.

Long-Term Receivables

Long-term receivables include minimum guaranteed amounts adjusted annually pertaining to future discounts for certain goods and services to be provided to Columbia as the result of a litigation settlement and subsequent revisions.

Accounts and Other Receivables

Accounts and other receivables for the Internal Service Fund include miscellaneous receivables outstanding from other Business Units that have not yet been collected. The amounts due to each Business Unit are reflected in the due to/from other Business Units account.

Asset Retirement Obligation, SFAS 143

Energy Northwest adopted the Statement of Financial Accounting Standards No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets" (SFAS 143) on July 1, 2002. SFAS 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation (ARO), such as nuclear decommissioning and site restoration liabilities, in the period in which it is incurred, rather than using a cost-accumulation approach (See Note G, Accounting Change: Accounting for Asset Retirement Obligations, for discussion regarding the impact of adopting SFAS 143).

Decommissioning and Site Restoration

Energy Northwest established decommissioning and site restoration funds for Columbia and monies are being deposited each year in accordance with an established funding plan.

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on decommissioning the plants at the end of each plant's operating life. In September 1998, the NRC approved and published its "Final Rule on Financial Assurance Requirements for Decommissioning Power Reactors." As provided in this rule, each power reactor licensee is required to report to the NRC the status of its decommissioning funding for each reactor or share of a reactor it owns. This reporting requirement began on March 31, 1999, and reports are required every two years thereafter. Energy Northwest submitted its most recent report to the NRC in March, 2003.

Energy Northwest's current estimate of Columbia's decommissioning cost is approximately $608 million (in 2003 dollars). This current estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

Site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC). Energy Northwest submitted a site restoration plan for Columbia that was approved by the EFSEC on June 12, 1995. Energy Northwest's current estimate of Columbia's site restoration cost is approximately $65 million (in 2003 dollars).

Both decommissioning and site restoration estimates (in 2003 dollars) are used as the basis for establishing a funding plan that includes escalation and interest earnings until decommissioning activities occur. Payments to the decommissioning and site restoration funds have been made since January 1985. The fair value of cash and investment securities in the decommissioning and site restoration funds as of June 30, 2003, totaled approximately $74.4 million and $7.6 million, respectively. Since September 1996, these amounts have been held and managed by BPA in external trust funds in accordance with NRC requirements and site certification agreements.

Materials and Supplies

Materials and supplies are valued at cost, using a weighted-average cost method.

Financing Expense, Bond Discount and Deferred Gain and Losses

Financing expenses and bond discounts are amortized over the terms of the respective bond issues using the bonds outstanding method.

In accordance with the Statement of Governmental Accounting Standard No.23, losses on debt refundings have been deferred and amortized as a component of interest expense over the shorter of the remaining life of the old or new debt. The balance sheet includes the original deferred amount less recognized amortization expense and is included as a reduction to the new debt.

Current Maturities of Revenue Bonds

Current maturities of revenue bonds payable from restricted assets are reflected in Long-Term Debt. Current maturities of bonds for which funds have not yet been restricted are reflected in Current Liabilities.

Accounts Payable and Accrued Expenses

Restricted Liabilities Internal Service Fund accounts payable and accrued expenses include $508,102 for unclaimed bearer bonds. Columbia includes $47.8 million for decommissioning and site restoration. Nuclear Project No. 1 includes $25.9 million for decommissioning and site restoration. The Nine Canyon Wind Project includes $466,989 for decommissioning and site restoration.

Current Liabilities Internal Service Fund accounts payable and accrued expenses include $645,558 for payroll and related benefits, $16 million for compensated absences, and $7.2 million for outstanding warrants. Columbia includes accrued expenses of $1.4 million for arbitrage penalty (as defined by the Internal Revenue Code). The Nine Canyon Wind Project includes $50,000 of accrued substation costs for Phase II and contract retainage amounts related to construction in the amount of $175,158.

Fair Value of Financial Instruments

The fair value of financial instruments has been estimated using available market information and certain assumptions. Considerable judgment is required in interpreting market data to develop fair value estimates and such estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The following methods and assumptions were used to estimate the fair value of each of the following financial instruments.

Financial instruments for which the carrying value is considered a reasonable approximation of fair value include: cash, accounts and other receivables, accounts payable and accrued expenses, advances from Members and others, other non-current liabilities and due to/from Participants, funds, and other Business Units. The fair values of investments (see Note C) and revenue bonds payable (see Outstanding Long-Term Debt Schedule) have been estimated based on quoted market prices for such instruments or based on the fair value of financial instruments of a similar nature and degree of risk.

Revenues

Energy Northwest accounts for expenses on an accrual basis and recovers, through various agreements, actual cash requirements for operations and debt service for Columbia, Packwood, Nuclear Project No. 1 and Nuclear Project No. 3. For these Business Units, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no equity is accumulated.

The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (liability) or as costs in excess of billings (asset), as appropriate. Such amounts will be settled during future operating periods.

Energy Northwest accounts for revenues and expenses on an accrual basis for the remaining Business Units. The difference between cumulative revenues and cumulative expenses is recognized as net revenue or losses and included in fund equity for each period.

Energy Northwest has accrued as income (contribution) from the Department of Energy, Renewable Energy Performance Incentive (REPI) that enables Nine Canyon Wind Project to receive revenue based on generation as it applies to the REPI bill. Fiscal Year 2003 resulted in an approximate amount of income of $230,000. The REPI was created as part of the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under Section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Income amounts were recorded upon Energy Northwest's application for participation in the REPI program, and are based on the qualifying generation data submitted to the Department of Energy.

Concentration of Credit Risk

Financial instruments which potentially subject Energy Northwest to concentrations of credit risk consist of available-for-sale investments, accounts receivable, other receivables, long-term receivables and costs in excess of billings. Energy Northwest invests exclusively in U.S. Government securities and agencies. Energy Northwest's accounts receivable and costs in excess of billings are concentrated with Project Participants and BPA through the net billing agreements. See Note E, Security - Nuclear Projects Nos. 1, 3, and Columbia and Security - Packwood Lake Hydroelectric Project. The long-term receivable is with a large and stable company which Energy Northwest considers to be of low credit risk. Other large receivables are secured through the use of letters of credit and other similar security mechanisms or are with large and stable companies which Energy Northwest considers to be of low credit risk. As a consequence, Energy Northwest considers the exposure of the Business Units to concentration of credit risk to be limited.

Statements of Cash Flows

For purposes of the statements of cash flows, cash includes unrestricted and restricted cash balances. Short-term, highly liquid investments are not considered cash equivalents.

NOTE C - CASH AND INVESTMENTS

Cash and investments for each Business Unit are separately maintained. Energy Northwest's deposits are insured by federal depository insurance or through the Washington Public Deposit Protection Commission. Energy Northwest resolutions and investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association and Federal Home Loan Banks. All investments are held for the benefit of the individual Energy Northwest Business Units by safekeeping agents, custodians, or trustees.

Investments are classified as available-for-sale and are stated at fair value with unrealized gains and losses reported in investment income. Available-for-sale investments at June 30, 2003, are categorized below to give an indication of the types and amounts as well as maturities of investments held by each Business Unit at year-end (See tables following).

AVAILABLE-FOR-SALE-INVESTMENTS
(Dollars in Thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
Columbia				
U.S. Government Agencies	$ 38,099	$ -	$ -	$ 38,099
Total	$ 38,099	$ -	$ -	$ 38,099
Packwood				
U.S. Government Securities	$ 2,796	$ 1	$ -	$ 2,797
Total	$ 2,796	$ 1	$ -	$ 2,797
Nuclear Project No. 1				
U.S. Government Securities	$ 255	$ -	$ -	$ 255
U.S. Government Agencies	53,349	$ -	$ -	53,349
Total	$ 53,604	$ -	$ -	$ 53,604
Nuclear Project No. 3				
U.S. Government Agencies	$ 42,666	$ -	$ -	$ 42,666
Total	$ 42,666	$ -	$ -	$ 42,666
Business Development Fund				
U.S. Government Agencies	$ 895	$ -	$ -	$ 895
Total	$ 895	$	$ -	$ 895
CT Project				
U.S. Government Agencies	$ 2,209	$ -	$ -	$ 2,209
Total	$ 2,209	$ -	$ -	$ 2,209
Internal Service Fund				
U.S. Government Agencies	$ 25,914	$ 3	$ -	$ 25,914
Total	$ 25,914	$ 3	$ -	$ 25,914
Nine Canyon Wind				
U.S. Government Securities	$ 756	$ 19	$ -	$ 775
U.S. Government Agencies	24,337	30	$ -	24,367
Total	$ 25,093	$ 49	$ -	$ 25,142

AVAILABLE-FOR-SALE-INVESTMENTS (Continued)
(Dollars in Thousands)

	< 1 year	1-5 years	5-10 years	> 10 years	Total
Columbia					
U.S. Government Agencies	$ 38,099	$ -	$ -	$ -	$ 38,099
Total	$ 38,099	$ -	$ -	$ -	$ 38,099
Packwood					
U.S. Government Securities	$ 2,797	$ -	$ -	$ -	$ 2,797
Total	$ 2,797	$ -	$ -	$ -	$ 2,797
Nuclear Project No. 1					
U.S. Government Securities	$ 255	$ -	$ -	$ -	$ 255
U.S. Government Agencies	53,349	$ -	$ -	$ -	53,349
Total	$ 53,604	$ -	$ -	$ -	$ 53,604
Nuclear Project No. 3					
U.S. Government Agencies	$ 42,666	$ -	$ -	$ -	$ 42,666
Total	42,666	$ -	$ -	$ -	$ 42,666
Business Development Fund					
U.S. Government Agencies	$ 895	$ -	$ -	$ -	$ 895
Total	$ 895	$ -	$ -	$ -	$ 895
CT Project					
U.S. Government Agencies	$ 2,209	$ -	$ -	$ -	$ 2,209
Total	$ 2,209	$ -	$ -	$ -	$ 2,209
Internal Service Fund					
U.S. Government Securities	$ 25,914	$ -	$ -	$ -	$ 25,914
Total	$ 25,914	$ -	$ -	$ -	$ 25,914
Nine Canyon Wind					
U.S. Government Securities	$ 775	$ -	$ -	$ -	$ 775
U.S. Government Agencies	24,367	$ -	$ -	$ -	24,367
Total	$ 25,142	$ -	$ -	$ -	$ 25,142

NOTE D - RETIREMENT BENEFITS

Substantially all Energy Northwest 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. T he 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, Administrative Services Division, 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.

Public Employee's Retirement System (PERS) Plans 1, 2, and 3

Plan Description

PERS is a cost-sharing, multiple-employer, defined benefit pension plan. Membership in the plan includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts (other than judges in a judicial retirement system); employees of legislative committees; college and university employees not in national higher education retirement programs; judges of district and municipal courts; non-certificated employees of school districts; and employees of local government, including Energy Northwest. The PERS system includes three plans. Participants who joined the system by September 30, 1977, are Plan 1 members. Those joining thereafter are enrolled in Plan 2, unless they exercise an option to transfer their membership to Plan 3. PERS participants joining the system on or after March 1, 2002, for state and higher education employees, or September 1, 2002, for local government employees 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. Retirement benefits are financed from employee and employer contributions and investment earnings. Retirement benefits in Plan 1 and Plan 2 are vested after completion of five years of eligible service. PERS Plan 3 participants are vested immediately.

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates and Plan 2 employer and employee rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at six percent and do not vary from year to year. The employer and employee contribution rates for Plan 2 and employer rate for Plan 3 are set by the director of the Department of Retirement Systems based on recommendations by the Office of the State Actuary to continue to fully fund the plan. All employers are required to contribute at the level established by state law. The methods used to determine the contribution requirements are established under state statute in accordance with chapters 41.40 and 41.45 Revised Code of Washington.

The required contribution rates for the defined benefit plan expressed as a percentage of current year covered payroll, as of June 30, 2003, were:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	1.32%	1.35%	1.32%
Employee	6.00%	0.65%	**

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

Both Energy Northwest and the employees make the required contributions.

Energy Northwest's required contributions for three years ended June 30, were:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
2003	$108,239	$1,077,106	$95,821
2002	$147,307	$1,238,861	N/A
2001	$410,640	$3,100,152	N/A

In addition to the pension benefits available through PERS, Energy Northwest offers post-employment life insurance benefits to retirees who are eligible to receive pensions under PERS Plan 1, Plan 2, and Plan 3. One hundred twenty-five retirees have elected to participate in this insurance. In 1994, Energy Northwest's Executive Board approved provisions which continued the life insurance benefit to retirees at 25 percent of the premium for employees who retire prior to January 1, 1995, and charged the full 100 percent premium to employees who retired after December 31, 1994. The life insurance benefit is equal to the employee's annual rate of salary at retirement for non-bargaining employees retiring prior to January 1, 1995. The cost of coverage for employees who retired after January 1, 1995, is $2.33 per $1,000 of coverage with a maximum limit of $10,000. Employees who retired prior to January 1, 1995, contribute $.58 per $1,000 of coverage while Energy Northwest pays the remainder. Premiums are paid to the insurer on a current period bais.

401(k) and 457 Plan Deferred Compensation Plan

Energy Northwest provides a 401(k) Deferred Compensation Plan (the 401(k) Plan), and a 457 Deferred Compensation Plan. Both Plans are defined contribution plans that were established to provide a means for investing savings by employees for retirement purposes. All permanent, full-time employees are eligible to enroll in the Plans. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations. For the 401(k) Plan, Energy Northwest matches 50 percent of the portion of the participant's salary deferral amount, which does not exceed 5 percent of the participant's 401(k) eligible earnings for the 401(k) Plan year. Participants direct the investment of their contributions. Participants are immediately vested in their contributions plus actual earnings thereon. During FY 2003, Energy Northwest contributed $1,887,237 in employer matching funds.

NOTE E - LONG-TERM DEBT

Each Energy Northwest Business Unit is financed separately. The resolutions of Energy Northwest authorizing issuance of revenue bonds for each Business Unit provide that such bonds are payable from the revenues of that Business Unit. All bonds issued under Resolutions Nos. 769, 775, and 640 for Nuclear Projects Nos. 1, 3, and Columbia, respectively, have the same priority of payment within the Business Unit (the "Prior Lien Bonds"). All bonds issued under Resolutions Nos. 835, 838, and 1042 for Nuclear Projects Nos. 1, 3, and Columbia, respectively, are subordinate to the Prior Lien Bonds and have the same subordinated priority of payment within the Business Unit (the "Electric Revenue Bonds").

During the year ended June 30, 2003, Energy Northwest issued, for Nuclear Projects 1, 3, and Columbia, the Series 2003-A Bonds, Series 2003-B Bonds, Series 2003-C Bonds, the Series 2003-D Bonds, the Series 2003-E Bonds, and Series 2003-F Bonds. The Series 2003-A Bonds, issued for Nuclear Project No.1, Nuclear Project No. 3, and Columbia are fixed rate bonds with an average coupon interest rate of 5.5 percent. The Series 2003-A Bond Proceeds of $714.1 million refunded $714.1 million of outstanding bonds having an average coupon interest rate of 5.59 percent. This transaction resulted in a net loss for accounting purposes of $757,092 for Nuclear Project 1, a net gain of $1,866,695 for Nuclear Project 3, and a net gain of $888,458 for Columbia. According to GASB 7 "Advance Refundings Resulting in Defeasance of Debt," the amortization of the gain and losses on the refundings are calculated based on the shorter of the life of the new debt compared to old debt.

The Series 2003-B Bonds, issued for Nuclear Project No.1, Nuclear Project No. 3, and Columbia, in the aggregate amount of $44.3 million, are taxable fixed rate bonds with an average coupon interest rate of 4.10 percent. The 2003-B Bond Proceeds of $44.3 million were used to refund $32.7 million of outstanding bonds, as well as for the payment of the Cost of Issuance, Underwriter's Discount, and Bond Insurance for all 2003 bonds. This transaction resulted in a net loss for nuclear project No. 1; Nuclear Project No. 2, and Columbia Generating Station of $17,881,186, $20,840,140 and $4,501,741 respectively.

The Series 2003-C Bonds, issued for Nuclear Project No. 1, in an aggregate amount of $200.5 million, are auction rate Bonds with 7-day and 35-day auction periods. This transaction resulted in a net gain to Nuclear Project No. 3 of $663,028.

The Series 2003-D Bonds, issued for Nuclear Project No. 3, in an aggregate amount of $201.1 million, are variable rate demand Bonds with weekly reset periods. This transaction resulted in a net gain to Nuclear Project No. 3 of $1,186,237.

The Series 2003-E Bonds, issued for Nuclear Project No. 3, in an aggregate amount of $98.0 million, are variable rate demand Bonds with weekly reset periods. The Series 2003-C/D/E Bonds were used to refund $499.6 million of outstanding bonds, all of which were called for redemption on July 1, 2003. As a result, the refunded bonds are considered to be defeased and the liability for these bonds has been removed from long-term debt. This transaction resulted in a net loss to Nuclear Project No. 3 of $203,228.

The Series 2003-F Bonds, issued for Columbia, in an aggregate amount of $41.3 million, are fixed rate bonds with an average coupon interest rate of 5.08 percent. The Series 2003-F Bonds were issued for the purpose of refunding certain short-term indebtedness, to pay costs of other capital improvements at Columbia, and to pay costs relating to the issuance of the Series 2003-F Bonds.

In prior fiscal years, Energy Northwest also defeased certain revenue bonds by placing the net proceeds from the refunding bonds in irrevocable trusts to provide for all required future debt service payments on the refunded bonds until their dates of redemption. Accordingly, the trust account assets and liability for the defeased bonds are not included in the financial statements in accordance with GASB Nos. 7 and 23. Including the Fiscal Year 2003 defeasements, approximately $771,210 million, $610,200 million, and $523,740 million of defeased bonds were not called or had not matured at June 30, 2003, for Nuclear Projects No.'s 1, 3, and Columbia, respectively.

During the Fiscal Year ended June 30, 2003, Energy Northwest also issued, for the Nine Canyon Wind Project, the Series 2003 Wind Project Revenue Bonds. The Series 2003 Bonds, in aggregate principal amount of $21.7 million, are fixed rate bonds with an average coupon interest rate of 4.51 percent. The Series 2003 Bonds were issued to finance the costs of acquiring, constructing and installing Phase II of the Project which consists of an additional 12 wind turbines.

Outstanding revenue bonds for the various Business Units as of June 30, 2003, and future debt service requirements for these bonds are presented at the end of the Financial Section of this report.

The refinancings entered into during the year have resulted in fixed rate debt being defeased by variable rate debt. This has exposed a portion of our outstanding debt to movements in interest rates. Our objective in managing this interest rate exposure is to limit the impact of interest rate changes on earnings and cash flows, and to reduce overall borrowing costs. To achieve these objectives, we maintain a mix of medium and long-term fixed rate debt.

Security - Nuclear Projects Nos. 1, 3, and Columbia

Project Participants have purchased all of the capability of Nuclear Projects Nos. 1, 3, and Columbia. BPA has in turn acquired the entire capability from the Participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the Business Units, Participants are obligated to pay Energy Northwest their pro rata share of total annual costs of the respective Projects, including debt service on bonds relating to each Business Unit, and BPA in turn is obligated to pay the Participants identical amounts by reducing amounts due to BPA by Participants under BPA power sales agreements. The net-billing agreements provide that Participants and BPA are obligated to make such payments whether or not the Projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Projects' output.

On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 Project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the Projects. Energy Northwest entered into an agreement with BPA to provide for continuation of the present budget approval, billing and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among Energy Northwest and private companies was terminated in fiscal year 1999. The ownership of all real and personal property interests was transferred to Energy Northwest.

Security - Packwood Lake Hydroelectric Project

Energy Northwest, Benton County PUD, and Franklin County PUD have signed Power Sales agreements which became effective November 4, 2002, and run through October 30, 2003. A subsequent one-year extension has been executed for the period beginning November 1, 2003, and extending through October 30, 2004. Benton and Franklin County PUD's agree to pay Energy Northwest in exchange for the total output of electric capacity and energy delivered from the Packwood Generation Project. The Packwood Participants are obligated to pay annual costs of the Project including debt service, whether or not the Project is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of the bond resolution. The Participants share project revenue as well.

NOTE F - COMMITMENTS AND CONTINGENCIES

Nuclear Project No. 1 Termination

Since the Nuclear Project No. 1 termination, Energy Northwest has been planning for the demolition of Nuclear Project No. 1 and restoration of the site, recognizing that there is no market for the sale of the Project in its entirety and to date, no viable alternative use has been found. The final level of demolition and restoration will be in accordance with agreements discussed later in Note F under "Nuclear Projects Nos. 1 and 4 Site Restoration."

Nuclear Project No. 3 Termination

In June 1994, the Nuclear Project No. 3 Owners Committee voted unanimously to terminate the Project. During 1995, a group from Grays Harbor County, Washington, formed the Satsop Redevelopment Project (SRP). The Satsop Redevelopment Project introduced legislation with the State of Washington under Senate Bill No. 6427, which passed and was signed by the Governor of the State of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 and Nuclear Project No. 5 exists for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights. In February 1999, Energy Northwest entered into a transfer agreement with the Satsop Redevelopment Project (SRP) to transfer the real and personal property at the site of Nuclear Project No. 3 and Nuclear Project No. 5. The SRP also agreed to assume regulatory responsibility for site restoration. Therefore, Energy Northwest is no longer responsible to the State of Washington and Washington Energy Facility Site Evaluation Council (EFSEC) for any site restoration costs.

Nuclear Projects Nos. 1 and 4 Site Restoration

Site restoration requirements for Nuclear Projects Nos. 1 and 4 are governed by site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington EFSEC. and a lease agreement with the Department of Energy (DOE). Energy Northwest submitted a site restoration plan for Nuclear Projects Nos. 1 and 4 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 approved Energy Northwest's site restoration plan on June 12, 1995. In its approval, EFSEC recognized that there is uncertainty associated with Energy Northwest's proposed plan. Accordingly, EFSEC's conditional approval provides for additional reviews once the details of the plan are finalized. A new plan with additional details was submitted in Fiscal Year 2003. This submittal was used to calculate the Asset Retirement Obligations (ARO) discussed in Note G of the financial statements.

Business Development Fund Interest in Northwest Open Access Network

The Business Development Fund is a member of the Northwest Open Access Network ("NoaNet"). Members formed NoaNet pursuant to an Interlocal Cooperation Agreement for the development and efficient use of a communication network in conjunction with BPA for use by the Members and others.

The Business Development Fund has a 7.38 percent interest in NoaNet with an additional 25 percent step-up possible for a maximum 9.23 percent. As of June 30, 2003, NoaNet has $27 million in outstanding bonds. The members are obligated to pay the principal and interest on the bonds when due, in the event and to the extent that NoaNet's Gross Revenue (after payment of costs of Maintenance and Operation) is insufficient for this purpose. The maximum principal share (with step-up) the Business Development Fund could be required to pay is $2,490,800. It's important to note the Business Development Fund is not obligated to reimburse losses of NoaNet unless an assessment is made to NoaNet's members based on a two-thirds vote of the membership. In Fiscal Year 2003, the Business Development Fund contributed $119,796 to NoaNet based on an assessment by the NoaNet members. This equity contribution was reduced to zero at year-end because NoaNet had a negative net equity position of $13.3 million as of June 30, 2003. Future equity contributions, if any, will be treated the same until NoaNet has a positive equity position.

Other Litigation and Commitments

Energy Northwest is involved in various claims, legal actions and contractual commitments and in certain claims and contracts arising in the normal course of business. Although some suits, claims and commitments are significant in amount, final disposition is not determinable. In the opinion of management, the outcome of such litigation, claims or commitments will not have a material adverse effect on the financial positions of the Business Units or Energy Northwest as a whole. The future annual cost of the Business Units, however, may either be increased or decreased as a result of the outcome of these matters.

Nuclear Licensing and Insurance

Energy Northwest is a licensee of the Nuclear Regulatory Commission and is subject to routine licensing and user fees, to retrospective premiums for nuclear liability insurance, and to license modification, suspension, or revocation, or civil penalties in the event of violations of various regulatory and license requirements.

The Price-Anderson Act currently provides for nuclear liability insurance of over $10.6 billion per incident, which is covered by a combination of commercial nuclear insurance and mandatory industry self-insurance. Energy Northwest has purchased the maximum commercial insurance available of $300 million, which is the first layer of protection. The second layer of protection is provided through a mandatory industry self-insurance plan wherein each licensed nuclear facility required to participate in the plan (currently 105 participants) may be assessed up to $100.6 million per incident, subject to a maximum annual assessment of $10 million per year.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by Energy Northwest and BPA. The total amount of insurance purchased is currently $2.25 billion. The deductible for this coverage is $5 million per occurrence.

NOTE G - NEW ACCOUNTING PRONOUNCEMENT

Energy Northwest adopted SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets", on July 1, 2002 (see Note B, Summary of Significant Accounting Policies). This Statement requires an entity to recognize the fair value of a liability for an asset retirement obligation (ARO), measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets, such as nuclear decommissioning and site restoration liabilities, in the period in which it is incurred. Upon initial recognition of the AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted, risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Capitalized asset retirement costs are depreciated over the life of the related asset with accretion of the ARO liability classified as an operating expense on the statement of operations and fund equity each period. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss if the actual costs differ from the recorded amount. However, with regard to the net-billed Projects, BPA is obligated to provide for the entire cost of decommissioning and site restoration therefore, any gain or loss recognized upon settlement of the ARO results in an adjustment to either the excess of costs (liability) or costs in excess of billings (asset), as appropriate, as no net revenue or loss is recognized, and no equity is accumulated for the net-billed projects.

Energy Northwest has identified legal obligations to retire generating plant assets at the following business units: Columbia Generating Station, Nuclear Project No. 1, and Nine Canyon Wind Project. Decommissioning and site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the Nuclear Regulatory Commission (NRC) regulations and site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC) and a lease agreement with the Department of Energy (DOE; (see Notes B and F). Under the current agreement, the Nine Canyon Wind Project has the obligation to remove the generation facilities upon expiration of the lease agreement if requested by the lessors.

Packwood's obligation has not been calculated becaus4 the time frame and extent of the obligation was considered under this statement as indeterminate, as a result, no reasonable estimate of the asset retirement obligation can be made. An ARO will be required to be recorded if circumstances change. Management believe that these assets will be used in utility operations for the foreseeable future.

Upon adoption of SFAS 143 on July 1, 2002, Columbia Generating Station recorded an ARO of $70.222 billion at its net present value of $31.110 million, and increase depreciable assets by $21.768 million. Nuclear Project No. 1 recorded an ARO of $49.612 million at its net present value of $25.253 million, however, no asset retirement cost was recorded as the project was terminated prior to the adoption date. Prior obligations recorded with regard to the decommissioning obligation of Columbia and Nuclear Project No. 1 were reversed as of the adoption date. As a result of the net-billing arrangement, the adoption of SFAS 143 for Columbia Generating Station and Nuclear Project No. 1 did not result in a cumulative effect adjustment on the statement of operations and fund equity, rather the net impact resulted in an increase to costs in excess of billings in the amount of $24.994 million and $25.253 million, respectively. As of June 30, 2003, Columbia Generating Station has a net asset value of $21.249 million and an accumulated liability of $47.754 million. Nuclear Project No. 1 has an accumulated liability of $41.354 million.

During the year, Nine Canyon Wind Project recorded an ARO of $458,115 with regard to Phase I of the generation project which began commercial operations in September 2002. As of June 30, 2003, the Nine Canyon Wind Project had a recorded asset retirement cost asset value of $449,683 with accumulated depreciation of $8,432 and an ARO asset of $466,989.

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APPENDIX D-1

Upon delivery of 2004 Bonds
Bond Counsel proposes to render
an opinion in substantially the following form for each Project.

Energy Northwest

Goldman, Sachs & Co.

Citigroup Global Markets Inc.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

UBS Financial Services, Inc.

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$63,620,000/$461,685,000/$85,350,000] [Project 1/Columbia/Project 3] Electric Revenue and Refunding Bonds, Series 2004-A and Series 2004-B [and Series 2004-C] (the "2004 Bonds"). The 2004 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/ October 23, 1997/November 23, 1993], as amended by a resolution adopted on March 21, 2001, and (iii) a Supplemental Resolutions adopted by the Executive Board on May 21, 2004 (the "Supplemental Resolution"). The Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

The Series 2004-A Bonds [and Series 2004-C Bonds] are subject to redemption in the manner and upon the terms and conditions set forth in the Electric Bond Resolutions[, including mandatory redemption at par by application of sinking fund payments.] The Series 2004-B Bonds are not subject to redemption prior to their stated maturity. The 2004 Bonds rank junior as to security and payment to bonds issued and outstanding under the Prior Lien Resolution. The 2004 Bonds rank equally as to security and payment with all other Parity Debt.

In connection with the issuance of the 2004 Bonds, we have examined a certified transcript of all of the proceedings taken in the matter of the issuance of the 2004 Bonds. 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. Energy Northwest is a municipal corporation and joint operating agency, duly created and existing under the laws of the State, including particularly the Act, having the right and power under the Act to acquire, construct, own and operate the Project, adopt the Bond Resolutions, issue the 2004 Bonds and apply the proceeds of the 2004 Bonds in accordance with the Supplemental Resolution.

2. The Bond Resolutions have been duly and lawfully adopted by Energy Northwest, are in full force and effect, are valid and binding upon Energy Northwest and are enforceable in accordance with their terms. Energy Northwest's covenants in the Prior Lien Resolution to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the Prior Lien Bonds prior to paying the principal of and interest on the 2004 Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2004 Bonds have been duly and validly authorized and issued under the Act and the Bond Resolutions and constitute valid and binding special revenue obligations of Energy Northwest, enforceable in accordance with their terms and the terms of the Bond Resolutions. The 2004 Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2004 Bonds are not a debt of the State or any political subdivision thereof (other than Energy Northwest), and neither the State nor any other political subdivision of the State is liable thereon.

The opinions above are qualified to the extent that the enforcement of the rights and remedies of the owners of the 2004 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.

This opinion is given as of the date hereof and we assume no obligation to update, revise or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

Very truly yours,

Nancy M. Neraas

APPENDIX D-2

Upon delivery of the 2004 Bonds
Bond Counsel proposes to render
a supplemental opinion in substantially the following form for each Project.

Energy Northwest

Goldman, Sachs & Co.

Citigroup Global Markets Inc.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

UBS Financial Services Inc.

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$63,620,000/$461,685,000/$85,350,000] [Project 1/Columbia/Project 3] Electric Revenue and Refunding Bonds, Series 2004-A, Series 2004-B and [Series 2004-C] (the "2004 Bonds"). The Series 2004 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/ October 23, 1997/November 23, 1993], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on May 21, 2004 (the "Supplemental Resolution"). The Electric Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

In connection with the issuance of the 2004 Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/2/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/2/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement"), (collectively the "Agreements") by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State and such statutes and regulations as we deemed relevant to this opinion, including particularly the Act;

(b) The Constitution of the United States of America and such statutes and regulations as we deemed relevant to this opinion, including particularly the Bonneville Project Act of 1937, as amended (the "Bonneville Act"), the Flood Control Act of 1944, Public Law 88-552, as amended, the Federal Columbia River Transmission System Act of 1974, as amended, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, as amended;

(c) Certified copies of the Resolution and the Supplemental Resolution;

(d) Certified copies of the Net Billing Agreements and the Assignment Agreement;

(e) The Certificate of the Chairman or Vice Chairman of the Executive Board, dated the date hereof, certifying that (i) neither Energy Northwest nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) The Certificate of the Administrator, dated the date hereof, certifying that (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing

Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(g) Certified copies of the proceedings of Energy Northwest authorizing the execution and delivery of the Net Billing Agreements and the Assignment Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, *inter alia*, (i) the office of Administrator was duly established and is validly existing under the Bonneville Act, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the Assignment Agreement, and (iii) each of the Net Billing Agreements and the Assignment Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System*, *et al*., 752 F.2d 1423 (9th Cir. 1985), *cert. denied*, 474 U.S. 1055 (1986)) ("Springfield");

(j) A certified copy of Energy Northwest Resolution No. [769/640/775], as amended and supplemented (the "Prior Lien Resolution"); and

(k) Such other documents, agreements, proceedings, pleadings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon and based on the assumptions/exceptions conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Projects 1 and 3 consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville Power Administration and the Participants currently obligated under the Net Billing Agreements, enforceable against such parties in accordance with its terms.

The foregoing opinion is subject to the following limitations, qualifications, exceptions, and assumptions:

(A) In rendering the opinion as to the enforceability of the Net Billing Agreements as to the Participants, we have assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations as therein stated, under the Net Billing Agreements and Assignment Agreement. The assumption in the prior sentence does not limit or affect our opinion as to the enforceability of the Net Billing Agreements and Assignment Agreement against Bonneville.

(B) The enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

(C) In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the Chairman or Vice Chairman of the Executive Board and the Administrator referred to above in paragraphs (e) and (f); and (3) (A) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (B) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreement to which such Participant is a party and that all assignments of any Participant's obligations under the Net Billing Agreements were properly done, and (C) with respect to the Participant's obligations under the Net Billing Agreements, no violation of or conflict with the provisions of applicable law, and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

(D) The opinions expressed herein are qualified to the extent that the characterization of, and the enforceability of any rights or remedies in the Agreements, may be limited by concepts of materiality, reasonableness, good faith and fair dealing, and rules governing specific performance, injunctive relief, marshalling, subrogation and other equitable remedies, regardless of whether raised in a court of law or otherwise**.** The opinions expressed herein are based on an analysis of existing laws (including, but not limited to, the law that provides that Bonneville may make expenditures from the Bonneville Fund which have been included in Bonneville's budget submitted to Congress without further appropriation or fiscal year limitation), regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof.

(E) We express no opinion with respect to any provision for a remedy which is determined to be in the nature of a penalty, forfeiture or punitive damages, or which would provide the claimant with a duplication of damage awards or cumulative remedy, or which waives the applicability of any rule requiring an election of remedies. We express no opinion with respect to the obligation of Bonneville or any Participant to pay any debt or other obligation related to the Project on an accelerated basis.

(F) Our opinions are subject to the context rule of interpretation of contracts, which provide that even though terms of a contract may be unambiguous, courts may admit extrinsic evidence to interpret the contract.

This letter has been prepared solely for your use in connection with the transactions contemplated by the Agreement and should not be quoted in whole or in part or otherwise be referred to nor be relied upon by, filed with or furnished to, any governmental agency or other person or entity (other than your legal and professional advisors) without the prior consent of this firm. No attorney client relationship has existed or exists between our firm and Bonneville, the Participants or the Underwriters with respect to the subject matter hereof or by virtue of this opinion. This letter opinion speaks as of its date and we do not hereby undertake to update this letter opinion. The opinions expressed in this letter are limited to the matters set forth in this letter, and no other opinions should be inferred beyond the matters expressly stated.

Very truly yours,

PRESTON GATES & ELLIS LLP

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APPENDIX E

Upon delivery of the 2004 Bonds
Special Tax Counsel proposes to render
an opinion in substantially the following form.

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$62,485,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-A
$42,350,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A
$83,835,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-A
$1,135,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)
$12,715,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2004-B (Taxable)
$1,515,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable)
$26,620,000 Columbia Generating Station Electric Revenue Bonds, Series 2004-C

Ladies and Gentlemen:

We have acted as Special Tax Counsel in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and a joint operating agency of the State of Washington, of $62,485,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2004-A (the "Project 1 2004-A Bonds"), $42,350,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-A (the "Columbia 2004-A Bonds"), $83,835,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2004-A (the "Project 3 2004-A Bonds" and together with the Project 1 2004-A Bonds and the Columbia 2004-A Bonds, the "Series 2004-A Bonds"), "), $1,135,000 Project 1 Electric Revenue Refunding Bonds, Series 2004-B (Taxable) (the "Project 1 2004-B Taxable Bonds"), $12,715,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2004-B (Taxable) (the "Columbia 2004-B Taxable Bonds"), $1,515,000 Project 3 Electric Revenue Refunding Bonds, Series 2004-B (Taxable) (the "Project 3 2004-B Taxable Bonds", and together with the Project 1 2004-B Bonds and the Columbia 2004-B Bonds, the "Series 2004-B Taxable Bonds") and $26,620,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2004-C (the "Series 2004-C Bonds"). The Project 1 2004-A Bonds and the Project 1 2004-B Taxable Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), and Resolution No. 835, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on May 21, 2004 (the "Project 1 Resolution"). The Columbia 2004-A Bonds, the Columbia 2004-B Taxable Bonds and the Series 2004-C Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted by Energy Northwest on October 23, 1997, as amended and supplemented, and a supplemental resolution adopted on May 21, 2004 (the "Columbia Resolution"). The Project 3 2004-A Bonds and the Project 3 Series 2004-B Taxable Bonds are being issued pursuant to the Act and Resolution No. 838, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on May 21, 2004 (the "Project 3 Resolution" and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Series 2004-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest. The Series 2004-B Taxable Bonds are being issued for the purpose of paying certain costs of issuance and other refunding costs relating to the Series 2004-A Bonds and the Series 2004-B Taxable Bonds. The Series 2004-C Bonds are being issued for the purpose of paying a portion of the costs of capital improvements at the Columbia Generating Station and paying costs of issuing the Series 2004-C Bonds.

In such connection, we have reviewed certified copies of the Resolutions; the Tax Matters Certificate executed and delivered by Energy Northwest on the date hereof and the Tax Matters Certificate executed and delivered on the date hereof by the Bonneville Power Administration (collectively, the "Tax Certificates"); the opinion of Preston Gates & Ellis LLP, as Bond Counsel; additional certificates of Energy Northwest, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

Certain agreements, requirements and procedures contained or referred to in the Resolutions, the Tax Certificates and other relevant documents may be changed and certain actions (including, without limitation, defeasance of Series 2004-A Bonds or the Series 2004-C Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. No opinion is expressed herein as to any Series 2004-A Bond, any Series 2004-C Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice or approval of counsel other than ourselves.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Our engagement with respect to the Series 2004-A Bonds, Series 2004-B Taxable Bonds and Series 2004-C Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolutions and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Series 2004-A Bonds or the Series 2004-C Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2004-A Bonds, the Series 2004-C Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated May 21, 2004, relating to the Series 2004-A Bonds, the Series 2004-B Taxable Bonds and the Series 2004-C Bonds, other than the portion titled "TAX MATTERS", or other offering material relating to those Bonds and express no opinion with respect thereto.

We have relied with your consent on the opinion of Preston Gates & Ellis LLP, Bond Counsel, with respect to the validity of the Series 2004-A Bonds, the Series 2004-B Taxable Bonds and the Series 2004-C Bonds and with respect to the due authorization and issuance of the Series 2004-A Bonds, the Series 2004-B Taxable Bonds and the Series 2004-C Bonds.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the opinion that interest on the Series 2004-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"), and that interest on the Series 2004-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act and Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code"). We also are of the opinion that interest on the Series 2004-B Taxable Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the 1986 Code. Interest on the Series 2004-A Bonds and the Series 2004-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

Except as expressly stated herein, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2004 Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

APPENDIX F

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE
FISCAL YEAR 2004 BUDGETS

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Albion, Idaho	0.004	0.016	0.003
	Alder Mutual Light Company, Washington	0.002		
	City of Bandon, Oregon	0.166	0.263	0.144
*	Public Utility District No. 1 of Benton County, Washington	4.965	5.350	4.295
	Benton Rural Electric Association, Washington	0.308	0.666	0.645
	Big Bend Electric Cooperative, Inc., Washington	0.179	1.610	0.374
	Blachly-Lane County Cooperative Electric Association, Oregon	0.234	0.272	0.491
	Blaine City Light, Washington	0.109	0.185	0.101
	City of Bonners Ferry, Idaho, Electric Department	0.115	0.182	0.099
	City of Burley, Idaho, Electric	0.179	0.694	0.155
	Canby Utility Board, Oregon	0.296	0.090	0.256
	City of Cascade Locks, Oregon	0.074	0.054	0.064
	Central Electric Cooperative, Inc., Oregon	0.462	0.586	0.966
	Central Lincoln People's Utility District, Oregon	4.169	4.017	3.607
	City of Centralia, Washington, Electric Light Department	0.298	0.739	0.258
*	Public Utility District No. 1 of Chelan County, Washington	0.501		0.433
	City of Cheney, Washington, Light Department	0.511	0.539	0.442
	Public Utility District No. 1 of Clallam County, Washington	1.157	1.769	1.001
	Public Utility District No. 1 of Clark County, Washington	14.305	6.151	13.633
	Clatskanie People's Utility District, Oregon	0.418	1.996	0.530
	Clearwater Power Company, Idaho	0.274	0.775	0.573
	Columbia Basin Electric Cooperative, Inc., Oregon	0.161	0.673	0.338
	Columbia Power Cooperative Association, Oregon	0.042	0.143	0.088
	Columbia Rural Electric Association, Inc., Washington	0.621	0.761	1.298
	Consolidated Irrigation District No. 19, Washington	0.005		0.005
	Consumers Power, Inc., Oregon	1.068	0.453	2.242
	Coos-Curry Electric Cooperative, Inc., Oregon	0.232	1.634	0.781
	Town of Coulee Dam, Washington, Light Department	0.048	0.137	0.041
	Public Utility District No. 1 of Cowlitz County, Washington	7.379	5.525	3.461
	City of Declo, Idaho	0.026	0.019	0.023
	Public Utility District No. 1 of Douglas County, Washington	0.044		0.049
	Douglas Electric Cooperative, Inc., Oregon	0.331	0.363	0.692
	City of Drain, Oregon, Light and Power	0.096	0.218	0.083
	East End Mutual Electric Company, Ltd., Idaho	0.011	0.033	0.023
	Town of Eatonville, Washington	0.010		
	City of Ellensburg, Washington	0.780	1.028	0.675
	Elmhurst Mutual Power and Light Co., Washington	0.170		
	Eugene Water & Electric Board, Oregon	0.061		
	Fall River Rural Electric Cooperative, Inc., Idaho	0.188	0.409	0.393
	Farmers Electric Co., Idaho	0.005	0.041	0.011
*	Public Utility District No. 1 of Ferry County, Washington	0.105	0.171	0.091
	City of Fircrest, Washington			

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	Flathead Electric Cooperative, Inc., Montana	0.123	0.370	0.257
	City of Forest Grove, Oregon, Light and Power Department	0.470	0.181	0.091
*	Public Utility District No. 1 of Franklin County, Washington	1.330	2.370	1.151
	Glacier Electric Cooperative, Inc., Montana	0.098		
*	Public Utility District No. 2 of Grant County, Washington	0.486		0.420
*	Public Utility District No. 1 of Grays Harbor County, Washington	2.769	3.075	2.386
	Harney Electric Cooperative, Inc., Oregon	0.105	0.719	0.221
	City of Heyburn, Idaho	0.167	0.504	0.145
	Hood River Electric Cooperative, Oregon	0.224	0.502	0.469
	Idaho County Light and Power Cooperative Association, Inc., Idaho	0.047	0.186	0.098
	City of Idaho Falls, Idaho, Electric Division	0.908	2.376	0.787
	Inland Power & Light Company, Washington	0.907	1.222	1.915
*	Public Utility District No. 1 of Kittitas County, Washington	0.238	0.220	0.206
*	Public Utility District No. 1 of Klickitat County, Washington	0.517	1.009	0.448
	Kootenai Electric Cooperative, Inc., Idaho	0.212	0.391	0.443
	Lakeview Light and Power Company, Washington	0.168		
	Lane Electric Cooperative, Inc., Oregon	0.537	1.452	1.123
	Public Utility District No. 1 of Lewis County, Washington	1.276	2.274	1.103
	Lincoln Electric Cooperative, Inc., Montana	0.087	0.255	0.182
	Lost River Electric Cooperative, Inc., Idaho	0.056	0.202	0.118
	Lower Valley Power and Light, Inc., Wyoming	0.266	0.820	0.557
*	Public Utility District No. 1 of Mason County, Washington	0.186	0.231	0.161
*	Public Utility District No. 3 of Mason County, Washington	1.274	1.446	1.265
	Town of McCleary, Washington	0.069	0.234	0.059
	McMinnville Water and Light, Oregon	1.141	1.227	0.547
	Midstate Electric Cooperative, Inc., Oregon	0.336	0.488	0.704
	City of Milton, Washington	0.027		
	Milton-Freewater Light and Power, Oregon	0.238	0.583	0.002
	City of Minidoka, Idaho	0.001	0.005	0.001
	Missoula Electric Cooperative, Inc., Montana	0.168	0.294	0.352
	City of Monmouth, Oregon	0.679	0.236	0.588
	Nespelem Valley Electric Cooperative, Inc., Washington	0.059	0.149	0.123
	Northern Lights, Inc., Idaho	0.234	0.455	0.489
	Northern Wasco County People’s Utility District, Oregon	0.246	0.051	0.213
	Ohop Mutual Light Company, Washington	0.025		
	Okanogan County Electric Cooperative, Inc., Washington	0.038	0.190	0.079
*	Public Utility District No. 1 of Okanogan County, Washington	0.255	1.042	0.143
	Orcas Power and Light Company, Washington	0.257	0.725	0.733
*	Public Utility District No. 2 of Pacific County, Washington	1.006	1.503	0.870
	Parkland Light and Water Company, Washington	0.096		
	Public Utility District No. 1 of Pend Oreille County, Washington	0.055		0.047
	Peninsula Light Company, Washington	0.261		
	City of Port Angeles, Washington	0.665	2.416	0.576
	Raft River Rural Electric Cooperative, Inc., Idaho	0.224	0.853	0.468
	Ravalli County Electric Cooperative, Inc., Montana	0.195	0.301	0.409
*	City of Richland, Washington, Energy Service Department	1.828	2.780	1.592
	Riverside Electric Company, Idaho	0.007	0.020	0.015
	City of Rupert, Idaho, Electric Department	0.123	0.348	0.106

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	Salem Electric, Oregon	0.662	0.453	1.385
	Salmon River Electric Cooperative, Inc., Idaho	0.046	0.170	0.097
	City of Seattle, Washington, City Light Department	8.605	7.193	7.206
*	Public Utility District No. 1 of Skamania County, Washington	0.321	0.547	0.278
*	Public Utility District No. 1 of Snohomish County, Washington	19.584	15.363	19.334
	South Side Electric Lines, Inc., Idaho	0.032	0.073	0.067
	City of Springfield, Oregon, Utility Board	0.228	0.363	0.238
	Town of Steilacoom, Washington	0.038		
	City of Sumas, Washington	0.021	0.048	0.018
	Surprise Valley Electrification Corp., California	0.049	0.323	0.102
*	Tacoma Power, Washington	5.971		5.803
	Tanner Electric Cooperative, Washington	0.050	0.122	0.104
	Tillamook People's Utility District, Oregon	0.963	1.729	0.833
	Umatilla Electric Cooperative, Oregon	0.997	0.036	2.107
	United Electric Cooperative, Inc., Idaho	0.320	0.466	0.670
	Vera Water and Power, Washington	0.323	0.701	0.401
	Vigilante Electric Cooperative, Inc., Montana	0.042	0.294	0.088
*	Public Utility District No. 1 of Wahkiakum County, Washington	0.229	0.328	0.198
	Wasco Electric Cooperative, Inc., Oregon	0.116	0.342	0.244
	Wells Rural Electric Company, Nevada	0.102		0.214
	West Oregon Electric Cooperative, Inc., Oregon	0.121	0.182	0.252
	Public Utility District No. 1 of Whatcom County, Washington	0.387		0.335
	TOTAL PARTICIPANT UTILITIES (112)	100.000	100.000	100.000

* Energy Northwest members.

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APPENDIX G

SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS

The following summary of certain provisions of the Net Billing Agreements, the Project No. 2 Project Agreement (hereinafter referred to as the "Columbia Project Agreement"), and the Assignment Agreements does not purport to be complete. A copy of the foregoing agreements may be obtained from Energy Northwest. The capitalization of any word or words which are not conventionally capitalized indicates that such words are defined in the Net Billing Agreements.

THE NET BILLING AGREEMENTS

On February 6, 1973, Energy Northwest, Bonneville and each Project 1 Participant entered into a Project 1 Net Billing Agreement. As originally executed, the Project 1 Net Billing Agreements contained a description of Project 1 which included the use of the generating facilities which are a part of HGP. Subsequently, on May 31, 1974, Energy Northwest, Bonneville and each Project 1 Participant entered into Amendatory Agreement No. 1 to each Project 1 Net Billing Agreement (the "Project 1 Amendatory Agreements"). Under the Project 1 Amendatory Agreements, among other things, the description of Project 1 was changed so that it no longer includes the use of HGP generating facilities. However, the provisions relating to the obligations incurred with respect to HGP after July 1, 1980 remain in effect. See "ENERGY NORTHWEST — HANFORD GENERATING PROJECT" in this Official Statement.

On January 4, 1971, Energy Northwest, Bonneville and each Columbia Participant entered into a Columbia Net Billing Agreement.

On September 25, 1973, Energy Northwest, Bonneville and each Project 3 Participant entered into a Project 3 Net Billing Agreement.

Many of the provisions of the Net Billing Agreements have been summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement. A summary of certain additional provisions of the Net Billing Agreements, as amended, follows. Except where the text indicates otherwise, reference to Project 1 Net Billing Agreements is to such Agreements as amended by the Project 1 Amendatory Agreements. The summary describes the common features of, and highlights the differences among, the Net Billing Agreements for each of Project 1, Columbia and Project 3. Each of the Net Billing Agreements for the same Net Billed Project is identical except as to the Participants' shares.

Term

Each Net Billing Agreement became effective upon its execution and delivery and will terminate as provided therein. See "Termination" below.

Although the Net Billing Agreements may be terminated prior to the maturity of the related Net Billed Bonds, the obligation of each of the Participants thereunder to pay its proportionate share of debt service on the related Net Billed Bonds shall continue until such Net Billed Bonds have been retired. Bonneville will continue to be obligated to offset or credit these payments against payments pursuant to the Participant's contracts with Bonneville.

Project 1 and Project 3 have been terminated, and portions of the Project 1 and Project 3 Net Billing Agreements have been terminated. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement.

Ownership and Operation

Energy Northwest covenants in the Columbia Net Billing Agreement to use its best efforts to arrange for the financing, design, construction, operation and maintenance of the Columbia Generating Station. Similar covenants of Energy Northwest under the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

Sale, Purchase and Assignment

Under the Columbia Net Billing Agreements, Energy Northwest sells, and each Participant purchases, the Participant's share of the Columbia Generating Station capability and each Participant in turn assigns its share of such capability to Bonneville. Such shares in the Columbia Generating Station for the fiscal year 2004 is shown in Appendix F in this Official Statement. Similar provisions in the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

The provisions of the Net Billing Agreements with respect to payments are summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement.

If Bonneville is unable to satisfy its obligation to a Participant by net billing, assignment or cash payment and determines that this condition will continue for a significant period, the affected Participant may direct that all or a portion of the energy associated with its share of the Columbia Generating Station capability be delivered by Energy Northwest for the Participant's account at a specified point of delivery, either for the expected period of such inability or the remainder of the term of the Columbia Net Billing Agreement, whichever is specified by the Participant when it elects to have such energy delivered to it. The amount of energy delivered will be limited to the amount of the Participant's share of the Columbia Generating Station capability for which payment by Bonneville cannot be made.

Energy Northwest Costs Payable Under Net Billing Agreements

All costs of Project 1, Columbia and Project 3 are payable under the respective Net Billing Agreements, and the Annual Budgets adopted by Energy Northwest shall make provision for all such costs, including accruals and amortizations, resulting from the ownership, operation (including cost of fuel), and maintenance of Project 1, Columbia and Project 3 and repairs, renewals, replacements, and additions to the Projects, including, but not limited to, the amounts which Energy Northwest is required under the respective Prior Lien Resolutions and Electric Revenue Bond Resolutions to pay into the various funds provided for in the resolutions for debt service and all other purposes. Each Participant is required to pay the amount specified in the Annual Budget, less amounts payable from sources other than payments under the Net Billing Agreements, multiplied by such Participant's share of Project capability.

Termination

If the Columbia Generating Station is ended pursuant to Section 15 of the Columbia Project Agreement, as described below under "THE PROJECT AGREEMENTS," Energy Northwest is required to give notice of termination of the Columbia Net Billing Agreement effective upon the date of termination of such Project Agreement. Energy Northwest will then terminate all activities relating to construction and operation of the Project and shall undertake the salvage and disposition or sale of such Project as provided in the Columbia Project Agreement.

In May 1994, the Board of Directors of Energy Northwest adopted a resolution which terminated Project 1 and a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. In June 1994, the Project 3 Owners Committee voted unanimously to terminate Project 3. In October 1998, Energy Northwest acquired all of the remaining assets of Project 3. Since that time, Energy Northwest has sold a portion of the Project 3 site to the Satsop Redevelopment Project and the balance of the site to Duke Energy Grays Harbor LLC. See "ENERGY NORTHWEST — PROJECT 1", "– PROJECT 3" and "– OTHER ACTIVITIES" and "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Post Termination Agreements."

For a description of payments required to be made following termination of the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement.

Modification and Assignment of Agreement

Each Net Billing Agreement provides that it shall not be amended, modified or otherwise changed by agreement of the parties thereto in any manner that will impair or adversely affect the security afforded by each Net Billing Agreement's provision for the payment of the principal, interest, and premium, if any, on the related Net Billed Bonds. The Net Billing Agreements further provide that, except for the reassignments of Participants' shares of Project capability provided for therein, no transfer or assignment of the Net Billing Agreements by any party thereto (except to the United States or an agency thereof) is permitted without the written consent of the other parties and that no assignment or transfer relieves the parties of any obligations thereunder.

Participants' Review Board

Each of the Net Billing Agreements for Columbia provides for the establishment of a Participants' Review Board consisting of nine members who are elected by the Participants in Columbia. Except in the event of an emergency requiring immediate action, copies of all bids, evaluations and proposed contracts and awards for amounts in excess of $500,000 shall be submitted to the Participant's Review Board. All Construction and Annual Budgets and fuel management plans, including amendments thereto, and plans for refinancing Columbia are required to be submitted by Energy Northwest to the Participants' Review Board within a reasonable time prior to the time such proposed budgets and plans are adopted by Energy Northwest.

The Net Billing Agreements provide that written recommendations of the Participants' Review Board shall be forwarded to Energy Northwest within a reasonable time and that Energy Northwest will consider such recommendations, giving due regard to Prudent Utility Practice and Energy Northwest's statutory duties. If Energy Northwest modifies or rejects a written recommendation of the Participants' Review Board, the Participants' Review Board may refer the matter to the Project Consultant in the manner described in the Project Agreement for his written decision and his decision shall be binding. Pending any such decision by the Project Consultant, Energy Northwest shall proceed in accordance with the Project Agreement. See "THE PROJECT AGREEMENTS — Term" hereinafter. The Net Billing Agreements provide that the provisions described above shall not affect the procedure for the settlement of any dispute between Bonneville and Energy Northwest under the Net

Billing Agreements or the Project Agreement. See "THE PROJECT AGREEMENTS — Bonneville's Approval and Project Consultant" hereinafter in this Appendix G.

Prudent Utility Practice has the same meaning as is given in "THE PROJECT AGREEMENTS — Design Licensing and Construction of the Project."

The Net Billing Agreements provide that, except as specifically provided in the Project Agreement, Energy Northwest shall not proceed with any item as proposed by it and not concurred in by Bonneville without approval of the Participants' Review Board.

THE PROJECT AGREEMENTS

On February 6, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 1 Project Agreement") which, among other things, provided standards for the design, licensing, financing, construction, fueling, operation and maintenance of Project 1, and for the making of any replacements, repairs or capital additions thereto. On May 31, 1974, Energy Northwest and Bonneville entered into Amendatory Agreement No. 1 to the Project 1 Project Agreement for the purpose of changing the description of Project 1 to conform to the changes made in the Project 1 Net Billing Agreements and to revise provisions relating to HGP.

On January 4, 1971, Energy Northwest and Bonneville entered into an agreement (the "Columbia Project Agreement") which, among other things, contains provisions with respect to the licensing, financing, construction, fueling, operation and maintenance of Columbia, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Columbia Net Billing Agreements.

On September 25, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 3 Project Agreement" and, together with the Project 1 Project Agreement and the Columbia Project Agreement, the "Project Agreements") which, among other things, contained provisions with respect to the financing, construction, operation and maintenance of Project 3, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Project 3 Net Billing Agreements.

Term

The Project 1 Project Agreement terminated as provided in Section 15 of the Project 1 Project Agreement in May 1994 when the Board of Directors of Energy Northwest adopted a resolution terminating Project 1.

The Columbia Project Agreement became effective upon its execution and delivery and will terminate as follows:

Columbia shall terminate and Energy Northwest shall cause Columbia to be salvaged, discontinued, decommissioned and disposed of or sold, in whole or in part, to the highest bidder or bidders, or disposed of in such other manner as the parties may agree when:

(a) Energy Northwest determines that it is unable to construct, operate, or proceed as owner of Columbia due to licensing, financing, or operating conditions or other causes which are beyond its control,

(b) The parties determine that Columbia is not capable of producing energy consistent with Prudent Utility Practice, or, if the parties disagree, the Project Consultant so determines, or

(c) Bonneville directs the end of Columbia pursuant to the provisions of the Columbia Project Agreement, which provides that if the estimated cost of a replacement or repair or capital addition required by a governmental agency after the date of commercial operation exceeds 20% of the then depreciated value of Columbia, Bonneville may direct that Energy Northwest end Columbia in accordance with Section 15.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. The Project 3 Owners Committee voted unanimously to terminate Project 3 and the Project 3 Project Agreement terminated in June 1994.

Design, Licensing and Construction of the Project

In the Columbia Project Agreement, Energy Northwest agrees, among other things, (i) to perform its duties and exercise its rights under such agreement in accordance with Prudent Utility Practice; (ii) to use its best efforts to obtain all licenses, permits and other rights and regulatory approvals necessary for the ownership, construction, and operation of the related Project; (iii) to construct the related Project in accordance with Prudent Utility Practice; and (iv) to keep Bonneville informed of all significant matters with respect to planning and construction of the Project.

"Prudent Utility Practice," as defined in the Columbia Project Agreement, at a particular time means any of the practices, methods and acts, including those engaged in or approved by a significant portion of the electrical utility industry prior to such time, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. In evaluating whether any matter conforms to Prudent Utility Practice, Bonneville, Energy Northwest and any Project Consultant shall take into account the fact that Energy Northwest is a municipal corporation with statutory duties and responsibilities and the objective to integrate the entire Project capability with the generating resources of the Federal System in order to achieve optimum utilization of the resources of that System taken as a whole and to achieve efficient and economical operation of that System.

Financing

With respect to Columbia, Energy Northwest agrees in the Columbia Project Agreement to use its best efforts to issue and sell Columbia Net Billed Bonds (if such Bonds may then be legally issued and sold) to finance the costs of Columbia and of any capital additions, renewals, repairs, replacements or modifications to Columbia.

The Columbia Project Agreement also provides that Energy Northwest may, after submitting its financing proposal to Bonneville, or shall, if requested by Bonneville, authorize the issuance and sale of additional Columbia Net Billed Bonds to refund outstanding Columbia Net Billed Bonds in accordance with the Columbia Net Billed Resolution. A proposal to refund outstanding Columbia Net Billed Bonds is required to be referred to the Project Consultant if, in the judgment of Bonneville or Energy Northwest, no substantial benefits will be achieved by such refunding. See "Bonneville's Approval and Project Consultant" below.

Net Billed Resolutions and resolutions of Energy Northwest supplementing or amending the Net Billed Resolutions are subject to approval by Bonneville, and Bonneville has approved each Net Billed Resolution and each supplemental resolution.

Budgets

Separate Annual Budgets for the Net Billed Projects will be prepared annually. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures." The Annual Budget and any amendment thereof are to be submitted to Bonneville for its approval. In the absence of any objection by Bonneville, the Annual Budget will become effective within 30 days after submittal, and within seven days in the case of any amendment thereof. Any item disapproved is required to be referred to the Project Consultant. See "Bonneville's Approval and Project Consultant" below.

Operation and Maintenance

Energy Northwest shall operate and maintain Columbia in accordance with Prudent Utility Practice and in accordance with the requirements of government agencies having jurisdiction.

Bonds for Replacements, Repairs and Capital Additions

If in any contract year the amounts in an Annual Budget relating to renewals, repairs, replacements and betterments and for capital additions necessary to achieve design capability or required by governmental agencies ("Amounts for Extraordinary Costs"), whether or not such amounts are costs of operation or costs of construction, exceed the amount of reserves, if any, maintained for such purpose pursuant to the Columbia Net Billed Resolutions plus the proceeds of insurance, if any, available by reason of loss or damage to Columbia, by the lesser of (1) $3,000,000 or (2) an amount by which the amount of Bonneville's estimate of the total of the net billing credits available in such contract year to the Participants in Columbia and the amounts of such reserves and insurance proceeds, if any, exceeds the Annual Budget for such contract year exclusive of Amounts for Extraordinary Costs, Energy Northwest is required to, in good faith, use its best efforts to issue and sell Columbia Net Billed Bonds to pay such excess.

Bonneville's Approval and Project Consultant

If a proposal submitted by Energy Northwest to Bonneville under any provision of the Columbia Project Agreement is not disapproved by Bonneville within the time specified or, if no time is specified, within seven days after receipt, the proposal is deemed approved. With certain exceptions specified in the Columbia Project Agreement (including Bonneville's right to approve a Net Billed Resolution and any supplemental resolutions), disapproval by Bonneville is required to be based solely on whether the proposal is consistent with Prudent Utility Practice.

If any proposal subject to approval by Bonneville is disapproved by Bonneville and an alternative proposal is suggested by Bonneville, Energy Northwest shall adopt such suggestion or, within seven days after receipt of such disapproval, shall appoint a Project Consultant acceptable to Bonneville to review the proposal. Proposals found by the Project Consultant to be consistent with Prudent Utility Practice shall become immediately effective. Proposals found by the Project Consultant to be inconsistent with Prudent Utility Practice shall be modified to conform to the recommendation of the Project Consultant or as the parties otherwise agree and shall become effective as and when modified. If any proposal referred to the Project Consultant has not been resolved and will affect the continuous operation of Columbia, Energy Northwest shall continue to operate Columbia and may proceed as proposed by Energy Northwest, or as proposed by Bonneville, or as modified by mutual agreement of Energy Northwest and Bonneville. If Energy Northwest proceeds with its proposal, and it is determined by the Project Consultant to be inconsistent with Prudent Utility Practice, Energy Northwest shall bear any net increase in the cost of construction or operation of Columbia resulting from such proposal without charge to Columbia to the extent such proposal is found by the Project Consultant to be inconsistent with Prudent Utility Practice.

ASSIGNMENT AGREEMENTS

In 1984, Energy Northwest and Bonneville executed Assignment Agreements for each of Project 1, Columbia and Project 3. The purpose of the Assignment Agreements is to assure that Bonneville receives the entire output of Project 1, Columbia, and Project 3, and to assure that Energy Northwest receives sufficient funds to pay all obligations incurred in connection with such Projects, including debt service.

The Assignment Agreements provide that, subject only to the Participants' rights under the Net Billing Agreements, Energy Northwest assigns to Bonneville any rights which it now has or may hereafter obtain in project capability by a reversion of any Participant's share in Project capability to Energy Northwest or by any other means. Bonneville accepted this assignment, and in the event that any Participant is determined not to be obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agrees to pay directly to Energy Northwest the amounts that would have been payable under the Net Billing Agreements for such Project capability.

The Assignment Agreements are designed to assure that Bonneville will obtain any interest Energy Northwest has or may hereafter obtain in Project capability, subject only to the Participants' rights and obligations under the Net Billing Agreements, and that the same economic and practical consequences will result for Bonneville and Energy Northwest as if Bonneville had acquired such interest in Project capability pursuant to the assignment of Project capability contained in the Net Billing Agreements.

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APPENDIX H-1

**SUMMARY OF CERTAIN PROVISIONS
OF ELECTRIC REVENUE BOND RESOLUTIONS
AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS**

The following summary is an outline of certain provisions contained in the Electric Revenue Bond Resolutions and the Supplemental Electric Revenue Bond Resolutions and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Electric Revenue Bond Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the Trustee. Capitalized terms not otherwise defined in this Appendix H-1 shall have the meanings ascribed to them in this Official Statement.

Definitions

"*Authorized Purpose*" shall mean any one or more of the purposes described in Section 201 of the Electric Revenue Bond Resolutions.

"*Bank Bond"* shall mean any Electric Revenue Bond owned by the Related Credit Issuer or its permitted assigns in connection with the provision of moneys under the Related Credit Facility.

"Certificate of Engineer" shall mean, as the context indicates, either (i) a signed document attesting to or acknowledging the matters therein stated or setting forth matters to be determined pursuant to the Electric Revenue Bond Resolution or (ii) any certificate, report or opinion of an Engineer, the Consulting Engineer or the Construction Engineer as to any matter called for by the Electric Revenue Bond Resolution.

"*Code*" shall mean the Internal Revenue Code of 1986, as amended and supplemented from time to time, and the applicable temporary, proposed, or final regulations promulgated by the United States Treasury Department thereunder or under the Internal Revenue Code of 1954, as amended.

"*Credit Facility*" shall mean a letter of credit, line of credit, insurance policy, surety bond, standby bond purchase agreement or standby payment agreement or similar obligation or instrument or any combination of the foregoing issued by a bank, insurance company or similar financial institution or by the parent corporation of any of the foregoing or by the State or the Federal Government or any agency, authority, instrumentality or subdivision thereof, including, without limitation, the Administrator.

"*Debt Service Deposit Date*" shall mean any date on which a deposit is required to be made into the related Debt Service Fund by each Electric Revenue Bond Resolution or any Supplemental Electric Revenue Bond Resolution.

"*Defeasance Obligations*" shall mean (a) any of the obligations described in clause (i) of the definition of Investment Securities, (b) Refunded Municipal Obligations, and (c) with respect to any Series of Electric Revenue Bonds, such other obligations as are described in the Supplemental Electric Revenue Bond Resolutions authorizing such Series.

"Electric Revenue Bond Resolution" shall mean Resolution No. 835, adopted on November 23, 1993, as amended and supplemented, Resolution No. 1042, adopted on October 23, 1997, as amended and supplemented, and Resolution No. 838, adopted on November 23, 1993, as amended and supplemented.

"*Engineer*" shall mean any nationally recognized independent engineer or engineering firm appointed by Energy Northwest, and may be the Consulting Engineer appointed pursuant to Resolutions Nos. 769, 640 and 775.

"*Investment Securities*" shall mean any of the following, if and to the extent that the same are legal for the investment of funds of Energy Northwest:

(i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America;

(ii) obligations of any agency, subdivision, department, division or instrumentality of the United States of America, including, without limitation, the Federal Home Loan Mortgage Corporation, the Federal Agricultural Mortgage Corporation, the Student Loan Marketing Association and the International Bank for Reconstruction and Development; or obligations fully guaranteed as to interest and principal by any agency, subdivision, department, division or instrumentality of the United States of America;

(iii) direct obligations of, or obligations guaranteed as to principal and interest by, any state or direct obligations of any agency or public authority thereof, insured or uninsured, provided such obligations are rated, at the time of purchase, in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(iv) bank time deposits evidenced by certificates of deposit and bankers' acceptances issued by any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), provided that such time deposits and bankers' acceptances (a) do not exceed at any one time in the aggregate five percent (5%) of the total of the capital and surplus of such bank or trust company, or (b) are secured by obligations described in items (i) or (ii) of this definition of Investment Securities, which such obligations at all times have a market value at least equal to such time deposits so secured;

(v) repurchase agreements with (1) any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), or (2) any securities broker which is a member of the Securities Investor Protection Corporation, which such agreements are secured by securities which are obligations described in items (i) or (ii) of this definition of Investment Securities, provided that each such repurchase agreement (a) is in commercially reasonable form and is for a commercially reasonable period, and (b) results in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the repurchaser) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest; provided that such securities acquired pursuant to such repurchase agreements shall be valued at the lower of the then current market value of such securities or the repurchase price thereof set forth in the applicable repurchase agreement;

(vi) certificates or other obligations that evidence ownership of the right to payments of principal of or interest on obligations of the United States of America or any state of the United States of America or any political subdivision thereof or any agency or instrumentality of the United States of America or any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a Trustee under the Electric Revenue Bond Resolutions, and provided further that, in the case of certificates or other obligations that evidence ownership of the right to payments of principal or interest on obligations of a state or political subdivision, the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which shall be rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(vii) investment agreements rated in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds or the long-term unsecured debt obligations of the issuer of which are rated in one of the two highest rating categories by the respective agency rating such investment agreements or investment agreements which result in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the counterparty to the investment agreement) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest;

(viii) bankers' acceptances drawn on and accepted or guaranteed by a commercial bank rated in either of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(ix) commercial paper rated, at the time of purchase, in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(x) shares of any publicly offered mutual fund of the type commonly known as a "money market fund" that, at the time of investment, has at least 85% of its assets directly invested in securities of the type described in items (i), (ii) and (iii) of this definition of Investment Securities; and

(xi) such other investments with respect to any Series of Electric Revenue Bonds as shall be specified in the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"Outstanding" or "outstanding" shall mean, as if any date, (a) when used with reference to Electric Revenue Bonds, all Electric Revenue Bonds theretofore or thereupon issued or authorized pursuant to the Electric Revenue Bond Resolution, except: (i) any Electric Revenue Bonds paid in full, surrendered for cancellation or cancelled at or prior to such date (including any Bond held in escrow pending settlement of any tender offer by Energy Northwest or the Trustee on its behalf, but excluding any Option Bond so held pending settlement of a purchase on a tender date); and (ii) Electric Revenue Bonds in lieu of or in substitution for which other Electric Revenue Bonds shall have been authenticated or delivered pursuant to the Electric Revenue

Bond Resolution; and (iii) Electric Revenue Bonds deemed to be no longer outstanding under the Electric Revenue Bond Resolution as provided therein or under any Supplemental Resolution authorizing the issuance of a Series of Electric Revenue Bonds, (b) when used with reference to Prior Lien Bonds shall have the meaning assigned to such term in the Prior Lien Resolution, and (c) when used with reference to Subordinate Lien Obligations shall have the meaning assigned to such term by the instrument or instruments under which such Subordinate Lien Obligations are issued.

"*Parity Debt*" shall mean bonds, notes or other obligations issued under a resolution or resolutions authorized pursuant to the Electric Revenue Bond Resolutions, the Electric Revenue Bonds and any Parity Reimbursement Obligation.

"*Parity Reimbursement Obligation*" shall mean a reimbursement obligation the payment of which, pursuant to the provisions of a Supplemental Electric Revenue Bond Resolution, is secured as to payment by the pledge created by the Electric Revenue Bond Resolutions.

"*Payment Agreement*" shall mean a written agreement which provides for an exchange of payments based on interest rates, or for ceilings or floors on such payments, or an option on such payments, or any combination, entered into on either a current or forward basis.

"*Payment Date*" shall mean each date on which interest shall be due and payable and each date on which both interest shall be due and payable and a scheduled Principal Installment (whether by payment of principal scheduled to mature or a sinking fund installment to be paid) shall be required to be made on any of the outstanding Electric Revenue Bonds according to their respective terms.

"*Principal Installment*" shall mean, as of any date of calculation and with respect to any Series or Subseries, as the case may be, (a) the principal amount of Electric Revenue Bonds (including any amount designated in, or determined pursuant to, the applicable Supplemental Electric Revenue Bond Resolution, as the "principal amount" with respect to any bonds) of such Series or subseries scheduled to mature on a certain future date for which no sinking fund installments have been established, or (b) the unsatisfied balance of sinking fund installments scheduled to be paid on a certain future date for Electric Revenue Bonds of such Series or subseries, or (c) if such future dates coincide as to different Electric Revenue Bonds of such Series or subseries, the sum of such principal amount and such unsatisfied balance scheduled to mature or to be paid on such future date; in each case in the amounts and on the dates as provided in the applicable Supplemental Electric Revenue Bond Resolution authorizing such Series or subseries regardless of any retirement of Electric Revenue Bonds except pursuant to Section 505 of the Electric Revenue Bond Resolutions or (d) that portion of a Parity Reimbursement Obligation which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid or that portion of a Parity Reimbursement Obligation payable on a certain future date which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid.

"Prior Lien Bonds" shall mean, collectively, the bonds heretofore or hereafter issued pursuant to the Prior Lien Resolutions.

"Prior Lien Resolutions" shall mean, collectively, Resolution No. 769, adopted on September 18, 1975, as amended and supplemented, Resolution No. 640, adopted June 26, 1973, as amended and supplemented, and Resolution No. 775, adopted December 3, 1975, as amended and supplemented.

"*Rating Agency*" shall mean Fitch, Inc. ("Fitch"), Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's Credit Markets Services ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

"Refunded Municipal Obligations" shall mean obligations of any state, the District of Columbia or possession of the United States of America or any political subdivision thereof, which obligations are rated in the highest rating category by at least two nationally recognized rating agencies and provision for the payment of the principal of and interest on which shall have been made by deposit with a Trustee or escrow agent of direct obligations of, or obligations guaranteed by, the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or any state, the District of Columbia or possession thereof in the capacity as custodian, the maturing principal of and interest on which when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession or political subdivision.

"*Reserve Account Requirement*" shall mean, with respect to a Series of Electric Revenue Bonds, the amount, if any, prescribed by the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Reserve Guaranty*" shall mean an insurance policy or surety bond provided by an insurer whose claims-paying ability is rated in either of the two highest rating categories by at least two nationally recognized rating agencies, or a letter of credit or other similar Credit Facility the long-term unsecured debt of the issuer of which is rated in either of the two highest rating categories by at least two nationally recognized rating agencies.

"Revenues" shall mean all income, revenues, receipts and profits derived by Energy Northwest through the ownership and operation by Energy Northwest of the related Project and all other moneys required to be deposited in the Revenue Fund created pursuant to the related Prior Lien Resolution.

"*Subordinate Lien Obligation*" shall mean any bond, note, certificate, warrant or other evidence of indebtedness of Energy Northwest authorized by the Electric Revenue Bond Resolution.

Effect of Amendments Adopted March 9, 2001 (Project 1, Columbia and Project 3)

The Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, amend the Project 1, Columbia and Project 3 Electric Revenue Bond Resolutions, respectively, to add a covenant to the effect that, from and after the issuance of the Series 2001-A Bonds, Energy Northwest will not issue or authorize the issuance of Prior Lien Bonds under the related Prior Lien Resolution and shall not otherwise create any other special fund or funds for the payment of bonds, warrants or other obligations which will rank on a parity with the pledge and lien on the Revenues created by such Prior Lien Resolution.

Each Supplemental Resolution also amends the related Electric Revenue Bond Resolution to add a definition of the term "Energy Northwest" and to change the definition of the term "System," as follows:

"Energy Northwest" shall mean the joint operating agency organized and existing under the provisions of the Act and formerly known as the Washington Public Power Supply System.

"System" shall mean Energy Northwest.

The Project 1 Supplemental Resolution further amends the Project 1 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 1 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 1 Electric Revenue Bond Supplemental Resolution, shall be known as "Energy Northwest Project 1 Electric Revenue Bonds."

The Columbia Supplemental Resolution further amends the Columbia Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution, from and after the date of adoption of the Columbia Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Columbia Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Columbia Generating Station Electric Revenue Bonds."

The Project 3 Supplemental Resolution further amends the Project 3 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 3 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 3 Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Project 3 Electric Revenue Bonds."

Electric Revenue Bond Resolutions to Constitute Contract (Section 103)

Each Electric Revenue Bond Resolution constitutes a contract between Energy Northwest and the owners from time to time of the Electric Revenue Bonds, and the issuer of a Credit Facility, if any, relating to such subseries of Electric Revenue Bonds; and the pledge made in each related Electric Revenue Bond Resolution and the covenants and agreements therein set forth to be performed on behalf of Energy Northwest shall be for the equal benefit, protection and security of the owners of any and all of the Electric Revenue Bonds and the issuer of any related Credit Facility where the obligation of Energy Northwest to reimburse such issuer is a Parity Reimbursement Obligation, each of which, regardless of time or times of maturity or due dates, shall be of equal rank without preference, priority or distinction of the Electric Revenue Bonds over any other thereof except as expressly provided in or permitted by the Electric Revenue Bond Resolutions.

Authorization of Bonds (Section 201)

The Project 1 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 1 Electric Revenue Bonds," the Columbia Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Columbia Electric Revenue Bonds," and the Project 3 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 3 Electric Revenue Bonds."

The Electric Revenue Bonds may be issued under each Electric Revenue Bond Resolution from time to time in series, which may consist of two or more subseries, pursuant and subject to the terms, conditions and limitations of the Electric Revenue Bond Resolutions and any Supplemental Electric Revenue Bond Resolutions providing for the issuance of Electric Revenue

Bonds, in such amounts as may be determined by Energy Northwest, for one or more of the following purposes: (i) refunding any Outstanding Prior Lien Bond, any Outstanding Electric Revenue Bond or any Outstanding Subordinate Lien Obligation; (ii) the payment, or reimbursement of Energy Northwest for the payment, of the costs of the acquisition, construction or installation of additional facilities or modifications to the related Project in compliance with the order or decision of any State or Federal agency or authority having competent jurisdiction; (iii) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of making renewals, repairs, replacements, improvements or betterments to the related Project, including costs associated with the upgrading of the output capacity of the related Project, including expenses incurred in connection with the upgrading of any operating license in connection therewith; (iv) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of capital additions, improvements or betterments to the related Project necessary to achieve design capability; (v) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of (1) decommissioning the related Project or (2) restoring the site of the related Project, in compliance with applicable Federal or State law or any order or decision of any State or Federal agency or authority having competent jurisdiction; (vi) payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of purchasing fuel for the related Project; (vii) providing funds for deposit into the Reserve Accounts or any other reserves established by any Supplemental Electric Revenue Bond Resolution for the payment of the principal of or interest on the Series of Electric Revenue Bonds authorized thereby and paying the costs incident to the issuance of such Series of Electric Revenue Bonds; and (viii) the payment, or the reimbursement of Energy Northwest for the payment, of the costs of any other purpose permitted by law; provided, however, that prior to the expenditure of the proceeds of any Series of Electric Revenue Bonds to pay the costs of the purposes described in items (iii) or (iv) above, Energy Northwest and the Trustee shall receive a Certificate of an Engineer stating that the making of such contemplated renewals, replacements, additions, betterments, improvements or extensions is consistent with prudent utility practice; provided, further, that any such Certificate delivered by an Engineer in connection with the expenditure of Electric Revenue Bond proceeds to pay the costs of an Authorized Purpose described in clause (iv) above shall also state the opinion of such Engineer that such Authorized Purpose is necessary or desirable to improve operating reliability, to increase output capacity or to reduce power costs.

Pledge Effected by the Electric Revenue Bond Resolutions (Section 202)

Energy Northwest pledges for the payment of the principal or redemption price of and interest on the Electric Revenue Bonds in accordance with their terms and the provisions of the Electric Revenue Bond Resolutions (i) the proceeds of the sale of the Electric Revenue Bonds pending application thereof in accordance with the provisions of the applicable Electric Revenue Bond Resolution or of any applicable Supplemental Electric Revenue Bond Resolution, (ii) subject to the provisions of each Electric Revenue Bond Resolution, all revenues and (iii) the Debt Service Fund established by each Electric Revenue Bond Resolution, including the investments, if any, therein; provided, however, that, subject to each Electric Revenue Bond Resolution, amounts on deposit to the credit of any Reserve Account in the Debt Service Funds are pledged only to the Series of Electric Revenue Bonds for which such Reserve Account was established pursuant to the Supplemental Electric Revenue Bond Resolutions authorizing such Series and may be applied only to pay the principal or redemption price, if any, of and interest on the Electric Revenue Bonds of such Series.

Except as may be otherwise provided in the Electric Revenue Bond Resolutions or in the Supplemental Electric Revenue Bond Resolutions authorizing a Series of Electric Revenue Bonds, the Electric Revenue Bonds of each such Series shall be equally and ratably payable and secured under the related Electric Revenue Bond Resolution without priority by reason of the date of adoption of the Supplemental Electric Revenue Bond Resolutions providing for their issuance or by reason of their Series or subseries, number or date, date of issue, execution, authentication or sale thereof, or otherwise.

The revenues and other moneys pledged and received by Energy Northwest shall immediately be subject to the lien of the pledge made by Energy Northwest under each Supplemental Electric Revenue Bond Resolution without any physical delivery or further act, and the lien of the pledge shall be valid and binding as against any parties having claims of any kind in tort, contract or otherwise against Energy Northwest, irrespective of whether such parties have notice thereof.

Refunding Bonds (Section 204)

All Electric Revenue Bonds issued to refund Outstanding Electric Revenue Bonds shall be authenticated and delivered by the Trustee only upon receipt by it, in addition to other documents required by the Electric Revenue Bond Resolutions (and in addition to further documents required by the provisions of any Supplemental Electric Revenue Bond Resolutions), of:

(i) irrevocable instructions to the Trustee, satisfactory to it, to give due notice of redemption of all the Electric Revenue Bonds to be redeemed on a redemption date or dates specified in such instructions;

(ii) if the Electric Revenue Bonds to be refunded are not to be redeemed within the next succeeding ninety (90) days, irrevocable instructions to the Trustee, satisfactory to it, to give due notice of any refunding of such Electric Revenue Bonds on a specified date prior to their maturity, as provided in Article VI of each Electric Revenue Bond Resolution or in the Supplemental Electric Revenue Bond Resolution which authorized such Electric Revenue Bonds to be refunded, and Section 1101 of each Electric Revenue Bond Resolution;

(iii) either (A) moneys (which may include all or a portion of the proceeds of the refunding Electric Revenue Bonds to be issued) in an amount sufficient to effect payment of the principal or the redemption price of the

Electric Revenue Bonds to be refunded, together with accrued interest on such Electric Revenue Bonds to the maturity or redemption date thereof, as the case may be, or (B) Defeasance Obligations in such principal amounts, of such maturities, bearing such interest and otherwise having such terms and qualifications and any moneys, as shall be necessary to comply with the provisions of Section 1101 of each Electric Revenue Bond Resolution, which Defeasance Obligations and moneys shall be held in trust and used only as provided in Section 1101 of each Electric Revenue Bond Resolution; and

(iv) such further documents and moneys as are required by the provisions of each Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolutions.

In addition, all refunding Electric Revenue Bonds of a Series issued to refund outstanding Prior Lien Bonds shall be authenticated and delivered by the Trustee, upon receipt by the Trustee, in addition to other documents required by the Electric Revenue Bond Resolutions, of evidence satisfactory to it that:

(i) irrevocable instructions have been delivered to the Prior Lien Bond Fund Trustee to give due notice of payment or redemption of all the Project 1, Columbia or Project 3 Prior Lien Bonds to be redeemed prior to their respective maturity dates on the date specified in such instructions, all in accordance with either Resolution Nos. 769, 640 or 775, as the case may be; and

(ii) such further documents and moneys as are required by the provisions of the applicable Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolution.

Subordinate Obligations (Section 205)

Nothing contained in the Electric Revenue Bond Resolutions prohibits or prevents Energy Northwest from authorizing and issuing bonds, notes, certificates, warrants or other evidences of any indebtedness for any purpose relating to the Net Billed Projects payable as to principal and interest from the revenues subject and subordinate to the deposits and credits required to be made to the funds established under the Electric Revenue Bond Resolutions or from securing such bonds, notes, certificates, warrants or other evidences of indebtedness and the payment thereof by a lien and pledge on the revenues junior and inferior to the lien and the pledge on the revenues created by either Resolution Nos. 769, 640 or 775, as the case may be, and created by the Electric Revenue Bond Resolutions.

Credit Facilities (Section 208)

Electric Revenue Bond Supplemental Resolutions providing for the issuance of a Series of Electric Revenue Bonds may provide that Energy Northwest obtain or cause to be obtained Credit Facilities providing for payment of all or a portion of the purchase price or Principal Installment or Redemption Price of, or interest due or to become due on specified Electric Revenue Bonds of such Series or any Subseries thereof, or providing for the purchase of such Electric Revenue Bonds or a portion thereof by the issuer of the Credit Facilities, or providing, in whole or in part, for the funding of the Reserve Accounts pursuant to Section 505 of each Electric Revenue Bond Resolution, provided such Credit Facility is a Reserve Guaranty. In connection therewith, Energy Northwest may enter into agreements with the issuers of the Credit Facility to provide for the terms and conditions thereof, including the security, if any, to be provided to such issuers.

Energy Northwest may secure the applicable Credit Facility by an agreement providing for the purchase of the Electric Revenue Bonds secured thereby with such adjustments to the rate of interest, method of determining interest, maturity, or redemption provisions as specified in the Supplemental Electric Revenue Bond Resolutions. Interest with respect to any Series of Electric Revenue Bonds so secured shall be calculated for purposes of the Reserve Account Requirement for such Series by using the actual rate of interest or, if applicable, the Certified Interest Rate on the Electric Revenue Bonds prior to adjustment under such agreement. Energy Northwest may also agree to reimburse directly the issuers of the Credit Facilities for any amounts paid thereunder together with interest thereon. Energy Northwest may provide that any such obligations to reimburse shall be Parity Reimbursement Obligations. In addition, Energy Northwest may, in connection with any such Credit Facility, agree to pay the fees and expenses of, and other amounts payable to, the issuers of such Credit Facilities, the payment of which may be secured by pledges of revenues, funds and other moneys pledged pursuant to the Electric Revenue Bond Resolutions on a parity with the pledges created by the Electric Revenue Bond Resolutions.

The Bond Fund (Section 501)

The Bond Fund created for the related Series of Prior Lien Bonds shall be continued for so long as any related Prior Lien Bonds remain Outstanding. As soon as practicable after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will direct, in writing, the Bond Fund Trustee under the related Prior Lien Resolutions to deliver forthwith all moneys and securities held in the Bond Fund, except for amounts, if any, required to be held by said Bond Fund Trustee to provide for the payment of the principal (including sinking fund installments) of premium, if any, and interest on the Prior Lien Bonds and expenses of the Bond Fund Trustee, to Energy Northwest, who will deposit such moneys and securities in the General Revenue Fund.

Establishment of Funds (Section 502)

The following special trust funds are established by each Electric Revenue Bond Resolution:

(a) General Revenue Fund, to be held and maintained by Energy Northwest; and

(b) Debt Service Fund, to be held and maintained by the Trustee. The Debt Service Fund shall include a separate Debt Service Account for each Series of Electric Revenue Bonds and a separate subaccount for each subseries of Electric Revenue Bonds issued under each Electric Revenue Bond Resolution and each such Debt Service Account and subaccount shall be designated using the designation of the Series or subseries, if any, to which such Debt Service Account or subaccount relates.

The existence of such funds shall be continued for so long as any Electric Revenue Bonds remain outstanding. Energy Northwest may establish pursuant to Supplemental Electric Revenue Bond Resolutions authorizing the issuance of Electric Revenue Bonds, additional funds, accounts and subaccounts for the purposes designated in such Supplemental Electric Revenue Bond Resolutions.

Disposition of Revenues (Section 503)

So long as the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, Energy Northwest has obligated and bound itself irrevocably to pay, after first providing for all required deposits and payments under the respective Prior Lien Resolutions to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that Energy Northwest has insufficient funds to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt (including the Trustee) and to each person entitled thereto, as applicable, its pro rata share of the amounts available to Energy Northwest for such payments. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the 25th day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each debt service subaccount in the related Debt Service Account, from the revenues theretofore deposited in the Revenue Fund the amount, which, when added to the amount then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each scheduled sinking fund installment required to be paid and the amount of interest due and payable, or if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest, on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, provided to be so paid pursuant to the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

On and after the date on which there shall be no Prior Lien Bonds outstanding, Energy Northwest covenants and agrees that it will pay into each General Revenue Fund as promptly as practical after receipt thereof all revenues and all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

General Revenue and Debt Service Funds (Sections 504 and 505)

General Revenue Fund. The amounts on deposit in each General Revenue Fund shall be trust funds in the hands of Energy Northwest and, subject to certain provisions described herein, shall be used and applied as provided in the applicable Electric Revenue Bond Resolution solely for the purpose of paying principal and interest on Parity Debt, the cost of operating and maintaining the related Project and paying all other costs, charges and expenses in connection with the costs of making repairs, renewals, replacements, additions, betterments and improvements to and extensions of the related Project and for purposes of paying all other charges and obligations against said revenues, income, receipts, profits and other moneys of whatever nature now or hereafter imposed thereon by law or contract, to the payment of which for such purposes said revenues and other moneys are pledged, including amounts required to be paid to the issuers of any Credit Facility pursuant to the provisions of any related Supplemental Electric Revenue Bond Resolution.

After the date on which there are no Prior Lien Bonds Outstanding, Energy Northwest shall pay, from the moneys on deposit in each General Revenue Fund, to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that the moneys on deposit in the General Revenue Fund shall be insufficient to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt and to each person thereof entitled thereto, as applicable, its pro rata share of the amounts on deposit in the General Revenue Fund. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the last Business Day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each relevant debt service subaccount in the related Debt Service Account, the amount, which, when added to the amount, if any, then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each sinking fund installment required to be paid, and the amount of interest due and payable, or, if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, required to be so paid pursuant to the provisions of the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the applicable Electric Revenue Bond Resolution to be so deposited.

Debt Service Fund. The Trustee shall, for each Series or Subseries of Electric Revenue Bonds Outstanding, pay from the moneys on deposit in each relevant Debt Service Account or subaccount of each Debt Service Fund (i) the amounts required for the payment of the principal, if any, due on each Payment Date and (ii) the amount required for the payment of interest due on each Payment Date and (iii) on any redemption date the amounts required to pay the redemption price of the Electric Revenue Bonds to be redeemed on such date, unless the payment of such redemption price shall be otherwise provided, and (iv) on any redemption date or date of purchase, the amounts required for the payment of accrued interest on Electric Revenue Bonds to be redeemed or purchased on such date unless the payment of such accrued interest shall be otherwise provided and (v) at the times and in the manner provided in the related Supplemental Electric Revenue Bond Resolution and the agreements between Energy Northwest and any issuer of a Credit Facility or counterparty to any Payment Agreement, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts provided to be so paid.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, Energy Northwest may, prior to the forty-fifth day preceding the due date of any sinking fund installment purchase Electric Revenue Bonds of the Series or Subseries, as the case may be, and maturity for which such sinking fund installment was established, at prices (including any brokerage and other charges) not exceeding the redemption price payable for such Electric Revenue Bonds when such Electric Revenue Bonds are redeemable by application of such sinking fund installment plus unpaid interest accrued to the date of purchase, such purchases to be made by the Trustee as directed in writing by an authorized officer of Energy Northwest.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, upon the purchase or redemption (other than by application of sinking fund installments) of any Electric Revenue Bond, an amount equal to the principal amount of the Electric Revenue Bond so purchased or redeemed shall be credited toward the sinking fund installments thereafter to become due as directed in writing by an authorized officer of Energy Northwest.

Energy Northwest may, at its option, in lieu of depositing all or any part of the sinking fund installments into each relevant Debt Service Account or subaccount thereof of each Debt Service Fund, furnish the Trustee with a Certificate of an authorized officer stating that Energy Northwest has purchased for cancellation term bonds of a Series or Subseries of Electric Revenue Bonds in the principal amount, and bearing the numbers, specified therein, and that said term bonds have not been previously included in any such Certificate; and thereupon the sinking fund installments with respect to the term bonds of such Series or subseries, as the case may be, may be reduced by the principal amount of such term bonds canceled, as provided by such Certificate.

Unless otherwise provided for a Series of Electric Revenue Bonds or subseries thereof, as the case may be, in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, as soon as practicable after the forty-fifth day preceding the due date of any such sinking fund installment, the Trustee shall proceed to call for redemption, pursuant to Article IV of each Electric Revenue Bond Resolution or the applicable Supplemental Electric Revenue Bond Resolutions, as the case may be, on such due date, Electric Revenue Bonds of the Series or subseries, as the case may be, and maturity for which such sinking fund installment was established in such amount as shall be necessary to complete the retirement of the principal amount specified for such sinking fund installment of the Electric Revenue Bonds of such Series or subseries, as the case may be, and maturity. The Trustee shall so call such Electric Revenue Bonds for redemption whether or not it then has moneys in each Debt Service Account or subaccount thereof of each Debt Service Fund established for such Series or subseries, as the case may be, sufficient to pay the applicable redemption price thereof on the redemption date. The Trustee shall apply to the redemption of the Electric Revenue Bonds on each such redemption date, the amount required for the redemption of such Electric Revenue Bonds.

Bond Proceeds Funds (Section 507)

The Supplemental Electric Revenue Bond Resolution providing for the issuance of any Series of Electric Revenue Bonds (exclusive of Refunding Bonds) will create and establish one or more special trust funds into which the proceeds of such

Series of Electric Revenue Bonds will be deposited and from which such proceeds will be disbursed to pay the Costs of the Authorized Purpose or Purposes for which such Series of Electric Revenue Bonds were issued (unless such Supplemental Electric Revenue Bond Resolution will provide for the deposit of such proceeds in one or more of such funds theretofore created and established). Each such fund (a "Bond Proceeds Fund") will be held in trust by Energy Northwest, for the benefit of the owners of the Electric Revenue Bonds pending application thereof in accordance with the terms of the related Supplemental Electric Revenue Bond Resolution. Payments from Bond Proceeds Fund will be as specified in the Supplemental Electric Revenue Bond Resolution authorizing the issuance of a related Series of Electric Revenue Bonds.

Amounts on deposit in any Bond Proceeds Fund, pending their application as provided in the Supplemental Electric Revenue Bond Resolution creating such Bond Proceeds Fund, will be subject to a prior and paramount lien and charge in favor of the owners of the Electric Revenue Bonds, and the owners of the Electric Revenue Bonds will have a valid claim on such moneys for the further security of the Electric Revenue Bonds until paid out or transferred as herein provided.

Investment of Funds (Section 508)

Moneys held in each Debt Service Fund shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee upon request of Energy Northwest (promptly confirmed in writing) solely in Investment Securities which shall mature or be subject to redemption at the option of the owner thereof on or prior to the respective dates when the moneys therein will be required for the purposes intended. However, moneys in each Reserve Account in each Debt Service Fund not required for immediate disbursement for the purpose for which said Account is created shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee at the direction of Energy Northwest (promptly confirmed in writing) solely in, and obligations credited to each Reserve Account shall be, Investment Securities which, unless otherwise provided in the related Supplemental Electric Revenue Bond Resolution, shall mature or be subject to redemption at the option of the owner thereof on or prior to the last maturity date of the related Series of Electric Revenue Bonds. The Trustee shall not be liable for any depreciation in value of any such investments. For the purpose of Section 508 of the Electric Revenue Bond Resolutions, the term "Investment Securities" shall be limited to obligations described in clauses (i) and (v) of the definition of Investment Securities.

Nothing in the Electric Revenue Bond Resolutions shall prevent any Investment Securities acquired as investments of funds held thereunder from being issued or held in book-entry form.

Valuation or Sale of Investments (Section 509)

Investment Securities in any fund or account created under the provisions of each Electric Revenue Bond Resolution shall be deemed at all times to be part of such fund or account and any profit realized from the liquidation of such investment shall be credited to such fund or account and any loss resulting from liquidation of such investment shall be charged to such fund or account. So long as the Project 1, Columbia or Project 3 Prior Lien Bonds shall remain Outstanding, any net profits remaining after accumulating the sum of all profits realized and losses suffered from the liquidation of such investments in any fund or account shall be retained in the related Debt Service Accounts (or subaccounts) of each Debt Service Fund, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing Series of Electric Revenue Bonds; provided, however, that if the money and value of investments in any Reserve Account in each Debt Service Fund shall exceed the applicable Reserve Account Requirement for the Series of Electric Revenue Bonds for which such Reserve Account was established, the amount of such excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest to each Debt Service Account established for such Series, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing such Series of Electric Revenue Bonds. After the date on which there shall be no Project 1, Columbia or Project 3 Prior Lien Bonds outstanding, any such net profits or excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest, or paid to, or retained in, each General Revenue Fund.

In computing the amount in any fund or account, Investment Securities therein shall be valued at cost or, if purchased at a premium or discount, at their amortized value. Any such computation shall include accrued interest on the Investment Securities paid as part of the purchase price thereof and not repaid. Such computation shall be made annually on June 30th for all funds and accounts established pursuant to the Electric Revenue Bond Resolutions and at such other times as Energy Northwest shall determine or as may be required by the Electric Revenue Bond Resolutions.

Except as otherwise provided in the Electric Revenue Bond Resolutions, the Trustee, as directed by an authorized officer of Energy Northwest (promptly confirmed in writing), shall use its best efforts to sell at the best price obtainable, or present for redemption, any Investment Securities held by the Trustee in any fund or account whenever it shall be necessary, and upon oral request (promptly confirmed in writing) from an authorized officer of Energy Northwest in order to provide moneys to meet any payment or transfer from such fund or account. The Trustee shall not be liable or responsible for any loss resulting from any such investment, sale, liquidation or presentation for investment made in the manner provided above.

Subject to the foregoing limitations, any moneys held by Energy Northwest or the Trustee under a particular Electric Revenue Bond Resolution may be pooled in order to make any purchase of Investment Securities or deposit of moneys held under such Electric Revenue Bond Resolution, which purchases or deposits are otherwise permitted thereunder; provided, however, that Energy Northwest and the Trustee shall at all times keep accurate and complete records of the Investment Securities so purchased and deposits so made in sufficient detail as will permit the application of such Investment Securities and deposits, and the proceeds thereof, solely for the purposes, at the times and in the manner provided in each Electric Revenue Bond Resolution.

Qualifications and Appointment of Trustee; Resignation or Removal Thereof; Successor Thereto (Section 601)

In the Supplemental Electric Revenue Bond Resolution providing for the issuance of the initial Series of Electric Revenue Bonds, Energy Northwest shall appoint a Trustee (the "Trustee") to hold and administer the Funds and Accounts created and established in each Electric Revenue Bond Resolution. The Trustee will be a commercial bank with trust powers or trust company with capital stock, surplus and undivided profits aggregating in excess of $50,000,000. The Trustee may be removed at the request of or upon the affirmative vote of (i) the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, or (ii) a majority of the members of the Executive Board of Energy Northwest, provided, however, that the Trustee may not be removed pursuant to the preceding clause (ii) upon the occurrence of an Event of Default or while such an Event of Default shall be continuing: provided further, that any removal will not take effect until the appointment of a successor and the acceptance by such successor in accordance with each Electric Revenue Bond Resolution.

In the event of the removal pursuant to clause (i) of the preceding sentence, resignation, disability or refusal to act of the Trustee, a successor may be appointed by the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, excluding any Electric Revenue Bonds held by or for the account of Energy Northwest, and such successor shall have all the powers and obligations of the Trustee under each Electric Revenue Bond Resolution theretofore vested in its predecessor; provided, that unless a successor Trustee has been appointed by the owners of Electric Revenue Bonds as aforesaid, Energy Northwest by a duly executed written instrument signed by a majority of the members of the Executive Board will concurrently appoint a Trustee to fill such vacancy until a successor Trustee will be appointed by the owners of Electric Revenue Bonds as authorized in this paragraph. Any successor Trustee appointed by Energy Northwest pursuant to this paragraph will, immediately and without further act, be superseded by a Trustee so appointed by the owners of Electric Revenue Bonds.

In the event of the removal of the Trustee pursuant to clause (ii) above, Energy Northwest will appoint a successor Trustee.

Any Trustee may resign at any time by giving not less than 180 days' notice to Energy Northwest in writing and to the Bondholders by publishing a notice of resignation in an Authorized Newspaper once within 10 days after the giving of such notice to the Energy Northwest; provided, however, that such resignation shall not take effect until the appointment of a successor and the acceptance of such successor in accordance with this Resolution.

The resigning Trustee, if within 50 days after the publication of notice of its resignation no successor Trustee has been appointed and accepted such appointment, may petition any court of competent jurisdiction for the appointment of a successor Trustee, or any owner of a Bond who has been an owner of a Bond for at least six months may, on behalf of such owner and others similarly situated, petition any such court for the appointment of a successor Trustee. Such court may thereupon, after such notice, if any, appoint a successor Trustee having the qualifications required hereby.

In case at any time any of the following shall occur: (i) any Trustee ceases to be eligible in accordance with the provisions of each Electric Revenue Bond Resolution and fails to resign after written request therefor has been given to such Trustee by Energy Northwest or by any owner of a Bond who has been a bona fide owner of a Bond for at least six months, or (ii) any Trustee becomes incapable of acting, or is adjudged a bankrupt or insolvent, or a receiver of such Trustee or of its property is appointed, or any public officer takes charge or control of such Trustee or of its property or affairs for the purpose of rehabilitation, conservation or liquidation, or (iii) any Trustee neglects or fails in the performance of its duties under each Electric Revenue Bond Resolution, then, in any such case, Energy Northwest may remove such Trustee by an instrument in writing signed by an Authorized Officer or any such owner of a Bond may, on behalf of himself and all others similarly situated, petition any court of competent jurisdiction for the removal of such Trustee. Such court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, remove such Trustee.

Any successor Trustee shall meet the qualifications of each Electric Revenue Bond Resolution. Such successor Trustee will execute, acknowledge and deliver to its predecessor, and also to Energy Northwest, an instrument in writing accepting such appointment under each Electric Revenue Bond Resolution, and thereupon such successor Trustee, without any further acts, deed or conveyance, shall become fully vested with all the rights, powers, trusts, duties and obligations of its predecessor in trust under each Electric Revenue Bond Resolution, with like effect as if originally named as Trustee; but such predecessor will, nevertheless, on the written request of Energy Northwest or such successor Trustee, execute and deliver an instrument transferring to such successor Trustee all rights, powers, trusts, duties and obligations of such predecessor in trust under each Electric Revenue Bond Resolution and will deliver all moneys held by it to such successor Trustee, together with an accounting of funds held by it under each Electric Revenue Bond Resolution. The successor Trustee will have no responsibility for the acts of the predecessor Trustee.

Upon acceptance of appointment by the successor Trustee, as provided in this Section, Energy Northwest will publish notice of the succession of such Trustee to the trusts hereunder at least once in an Authorized Newspaper. If Energy Northwest fails to publish such notice, within 10 days after acceptance of appointment by the successor Trustee, the successor Trustee will cause such notice to be published at the expense of Energy Northwest.

Any corporation into which a Trustee may be merged or with which it may be consolidated, or any corporation resulting from any merger or consolidation to which a Trustee is a party, or any corporation to which a Trustee may sell or transfer all or substantially all of its corporate trust business, will be the successor Trustee under each Electric Revenue Bond Resolution without the execution or filing of any paper or any further act on the part of the parties to each Electric Revenue Bond Resolution; provided such corporation meets the qualifications of each Electric Revenue Bond Resolution.

Certain Covenants (Article VII)

Energy Northwest covenants and agrees with the purchasers and owners of all Electric Revenue Bonds issued pursuant to the Electric Revenue Bond Resolution to, but not limited to, the following:

Compliance with Prior Lien Resolutions. So long as any of the Project 1 Prior Lien Bonds, the Columbia Prior Lien Bonds or the Project 3 Prior Lien Bonds are Outstanding, Energy Northwest shall comply in all respects with each of the provisions, covenants and agreements of or contained in Resolution Nos. 769, 640 and 775, respectively.

Concerning the Agreements and Prior Lien Resolutions. So long as any of the Electric Revenue Bonds are Outstanding, Energy Northwest will not (i) voluntarily consent to or permit any rescission of or consent to any amendment to or otherwise take any action under or in connection with any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds or (ii) voluntarily consent to or permit any rescission of or consent to any amendment to or modification of or otherwise take any action under or in connection with, each Project Agreement in the case of Columbia, each Assignment Agreement, each Property Disposition Agreement or each 1989 Letter Agreement which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds; and Energy Northwest shall perform all of its obligations under said Agreements and shall take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Electric Revenue Bonds afforded by the provisions of said Agreements. Energy Northwest will not, so long as any Project 1, Columbia or Project 3 Prior Lien Bonds remain Outstanding, consent to or agree to any change, amendment or modification of the Prior Lien Resolutions, respectively, which would in any way or manner prejudice or affect adversely the rights or interests of the owners of the Electric Revenue Bonds.

Encumbrance or Disposition of Project Properties; Termination of Projects. On and after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will not sell, mortgage, lease or otherwise dispose of any properties of the related Project, or permit the sale, mortgage, lease or other disposition thereof, except as provided below.

(i) Energy Northwest may sell, lease or otherwise dispose of all or any portion of the works, plants and facilities of a Project and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operation of a Project, provided, however, that if the original costs of the properties so to be disposed of was in excess of $5,000,000, an Engineer shall first certify that the properties to be disposed of are unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operations of a Project; provided, however, no such certification shall be required if such sale or other disposition takes place after a Project has been terminated. Monies received by Energy Northwest as the proceeds of any such sale, lease or other disposition of all or any portion of the properties of a Project shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds; provided, however, that if such sale, lease or other disposition of all or any portion of the properties of a Project is in connection with the replacement of such properties, all moneys received from such partial disposition of property may be transferred to the respective General Revenue Funds.

(ii) Energy Northwest may sell, lease or otherwise dispose of fuel for a price not less than the lesser of the cost to Energy Northwest thereof or the fair market value thereof at the time of such sale, lease or other disposition; provided, that any moneys received by Energy Northwest as proceeds of any such sale, lease or purchase shall be either transferred to the respective General Revenue Funds or used for the purchase or redemption of Electric Revenue Bonds.

(iii) In the event that the ownership of the properties of a Project or any part thereof shall be transferred from Energy Northwest through the operation of law, any moneys received by Energy Northwest as a result of any such transfer shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds.

(iv) Energy Northwest may terminate a Project at any time. Any moneys received by Energy Northwest from the disposition of the properties of a Project so terminated may be applied to the payment of the cost of decommissioning such Project including the cost of restoring the site thereof, and any amounts so received not required to pay such costs shall be applied as provided in paragraph (iii) above or in each Electric Revenue Bond Resolution.

Nothing contained in the Electric Revenue Bond Resolutions shall be construed to prevent Energy Northwest from constructing as a separate utility system any additional generating unit or units on or near the site of any Project, and using facilities of a Project in connection with the construction or operation therewith without compensation therefor; provided, however, that an Engineer shall certify to Energy Northwest and the Trustee that such use will not adversely affect the operations of the applicable Project or interfere with the performance by Energy Northwest of its obligations under the Electric Revenue Bond Resolutions; and provided further, however, that any compensation received by Energy Northwest on account of any such use shall be paid into the respective General Revenue Funds.

Notwithstanding the provisions of subsections (i) through (iv) above, moneys received by Energy Northwest as a result of any sale, lease, transfer or other disposition specified in such subsections and which are in excess of the amounts required for decommissioning and site restoration costs may be transferred to such funds or accounts determined by Energy Northwest or used to purchase or redeem Electric Revenue Bonds.

Insurance. Energy Northwest shall, to the extent available at reasonable cost with responsible insurers, keep, or cause to be kept, the works, plants and facilities comprising the properties of the related Project and the operation thereof insured, with policies payable to Energy Northwest for the benefit of Energy Northwest, the Participants and Bonneville, as their interests may appear, against risks of direct physical loss, damage to or destruction of such properties or any part thereof, and against accidents, casualties, or negligence, including liability insurance and employer's liability, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and such other insurance as may be agreed upon by the parties to the Columbia Project Agreement. To the extent such insurance is being maintained by Energy Northwest pursuant to the Prior Lien Resolutions, no such insurance need be maintained under the related Electric Revenue Bond Resolution. In the case of loss, including loss of revenue, caused by suspension or interruption of generation or transmission of power and energy by a Project, the proceeds of any insurance policy or policies covering such loss received by Energy Northwest, prior to the retirement of the related Prior Lien Bonds, shall be paid into the related Revenue Fund, and thereafter, shall be paid into the related General Revenue Fund. Within 60 days after the end of each fiscal year, Energy Northwest shall file, or cause to be filed, with the Trustee a certificate of an Engineer describing in reasonable detail the insurance on the Projects then in effect pursuant to the requirements of the related Electric Revenue Bond Resolution and stating whether, in its opinion, such insurance then in effect reasonably complies with the provisions hereof. Prior to the retirement of the Project 1, Columbia or Project 3 Prior Lien Bonds, the filing of such a certificate pursuant to the related Prior Lien Resolutions shall satisfy the requirement of the preceding sentence.

Books of Account; Annual Audit. Energy Northwest shall keep proper books of account for each Project, showing as a separate utility system the accounts of each Project in accordance with the rules and regulations prescribed by any governmental agency authorized to prescribe such rules, including the Division of Municipal Corporations of the State Auditor's office of the State of Washington, or other state department or agency succeeding to such duties of the State Auditor's office, and in accordance with the Uniform System of Accounts prescribed from time to time by the Federal Energy and Regulatory Commission, or any successor federal agency having jurisdiction over electric public utility companies owning and operating properties similar to each Project, whether or not Energy Northwest is required by law to use such system of accounts. Within one hundred twenty (120) days after the end of each fiscal year, Energy Northwest shall cause such books of account to be audited by independent certified public accountants of national reputation licensed, registered or entitled to practice and practicing as such under the laws of the State of Washington who, or each of whom, is in fact independent and does not have any interest, direct or indirect, in any contract with Energy Northwest other than his contract of employment to audit books of account of Energy Northwest, and who is not connected with Energy Northwest as an officer or employee of Energy Northwest. A copy of each audit report, annual balance sheet and income and expense statement showing in reasonable detail the financial condition of each Project as of the close of each fiscal year and summarizing in reasonable detail the income and expenses for such year, including the transactions relating to the funds and accounts and the amounts expended for maintenance and for renewals, replacements and gross capital additions to each Project shall be filed promptly with the Trustee and sent to any Bondholder filing with Energy Northwest a written request for a copy thereof. Each such audit report shall state therein that the auditor has examined and is familiar with the provisions of the related Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution relating to the matters set forth above, and that as to such matters Energy Northwest is in compliance therewith or, if not in compliance therewith, the details of such failure to comply and the action to be taken by Energy Northwest to be in compliance therewith.

Consulting Engineer. To the extent required by a Supplemental Electric Revenue Bond Resolution, Energy Northwest will, as prescribed in the Electric Revenue Bond Resolutions, retain a nationally recognized independent engineer or engineering firm (the "Consulting Engineer") on a continuous basis for the purpose of providing Energy Northwest immediate and continuous engineering counsel with respect to each Project; provided, however, that no Consulting Engineer need be retained so long as Energy Northwest retains a Consulting Engineer pursuant to the Prior Lien Resolutions.

Protection of Security; Additional Parity Indebtedness. Energy Northwest is duly authorized under all applicable laws to create and issue the Electric Revenue Bonds and to adopt the Electric Revenue Bond Resolutions and to pledge the revenues and other moneys, securities and funds purported to be pledged by the Electric Revenue Bond Resolutions in the manner and to the extent provided in the Electric Revenue Bond Resolutions. The revenues and other moneys, securities and funds so pledged are and will be free and clear of any pledge, lien, charge or encumbrance thereon, or with respect thereto, prior to, or of equal rank with, the pledge created by the Electric Revenue Bond Resolutions, so long as any of the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, except for the lien and pledge of the Prior Lien Resolutions, and all corporate action on the part of Energy Northwest to that end has been duly and validly taken. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

Subject to the provisions of the Prior Lien Resolutions, Energy Northwest will not hereafter create any other special fund or funds for the payment of bonds, warrants or other obligations or issue any bonds, warrants or other obligations payable out of or secured by a pledge of revenues or create any additional obligations which will rank on a parity with or in priority over the pledge and lien of such revenues created under the Electric Revenue Bond Resolutions, except that Energy Northwest may issue bonds, notes or other obligations, under a separate resolution or resolutions, which are payable from or secured by a pledge of the revenues and may create or cause to be created any lien or charge on such revenues, ranking on a parity with the pledge and lien created by the Electric Revenue Bond Resolutions, for any one or more of the purposes provided in the Electric Revenue Bond Resolutions or may create Parity Reimbursement Obligations. However, Energy Northwest shall not issue any such additional bonds, notes or other obligations or create Parity Reimbursement Obligations unless, on the date of issue of such bonds, the certain contracts or agreements described in the Electric Revenue Bond Resolutions are in full force and effect and no Event of Default under the Electric Revenue Bond Resolutions shall have occurred and be continuing.

Further Assurances. Energy Northwest will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights, revenues and other funds pledged or assigned to the payment of the obligations issued by Energy Northwest payable from the revenues of each Project, including the Electric Revenue Bonds or intended so to be, or which Energy Northwest may hereafter become bound to pledge or assign.

Tax Covenants. Energy Northwest covenants with the owners from time to time of the Electric Revenue Bonds that (i) throughout the term of the Electric Revenue Bonds and (ii) through the date that the final rebate, if any, must be made to the United States in accordance with Section 148 of the Code it will comply with the provisions of Sections 103 and 141 through 150 of the Code and all regulations proposed and promulgated thereunder that must be satisfied in order that interest on the Electric Revenue Bonds shall be and continue to be excluded from gross income for federal income tax purposes.

Energy Northwest shall not permit at any time or times any of the proceeds of the Electric Revenue Bonds or any other funds of Energy Northwest to be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Electric Revenue Bond to be an "arbitrage bond" as defined in Section 148 of the Code, or any successor provision of law.

Energy Northwest shall not permit at any time or times any proceeds of any Series of Electric Revenue Bonds or any other funds of Energy Northwest to be used, directly or indirectly, in a manner which would result in the exclusion of any Electric Revenue Bond from the treatment afforded by Section 103(a) of the Code.

Anything contained in the three preceding paragraphs to the contrary notwithstanding, Energy Northwest reserves the right to issue, from time to time, one or more Series of Electric Revenue Bonds the interest on which is includable in the gross income of the recipient thereof for federal income tax purposes ("Taxable Bonds"), provided that the issuance of any such Series of Taxable Bonds does not adversely affect the federal tax exemption of the interest on any other Series of Electric Revenue Bonds.

Events of Default and Remedies (Section 801)

The occurrence of one or more of the following events shall constitute an "Event of Default" under the Electric Revenue Bond Resolution to which such Event of Default relates:

(1) if payment of principal or the redemption price of any related Electric Revenue Bond shall not punctually be made when due and payable, whether at the stated maturity thereof, upon redemption or otherwise;

(2) if payment of the interest on any related Electric Revenue Bond shall not punctually be made when due;

(3) if payment of any related Parity Reimbursement Obligation shall not be punctually made when due;

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed (other than the covenant relating to compliance with the respective Prior Lien Resolutions), and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default

if corrective action is instituted within such period and diligently pursued until the failure is corrected; and provided further that the exclusion of the covenant relating to compliance with the respective Prior Lien Resolutions, shall not be construed to prevent the Trustee from enforcing any remedy it may have, at law or in equity, for a breach of such covenant;

(5) if an order, judgment, or decree shall be entered by any court of competent jurisdiction, with the consent or acquiescence of Energy Northwest, or if such order, judgment or decree, having been entered without the consent or acquiescence of Energy Northwest, shall not be vacated or set aside or discharged or stayed (or in case custody or control is assumed by said order, such custody or control shall not otherwise be terminated) within ninety (90) days after the entry thereof, and if appealed, shall not thereafter be vacated or discharged: (i) appointing a receiver, trustee or liquidator for Energy Northwest; or (ii) assuming custody or control of the whole or any substantial part of the applicable Project under the provisions of any law for the relief or aid of debtors; or (iii) approving a petition filed against Energy Northwest under the provisions of 11 USC 901-946, as amended (the "Bankruptcy Act"); or (iv) granting relief to Energy Northwest under any amendment to said Bankruptcy Act, or under any other applicable Bankruptcy Act, which shall give relief substantially similar to that afforded by Chapter IX thereof; and

(6) if Energy Northwest shall (i) admit in writing its inability to pay its debts generally as they become due; or (ii) file a petition in bankruptcy or seeking a composition of indebtedness; or (iii) make an assignment for the benefit of its creditors; or (iv) file a petition or any answer seeking relief under the Bankruptcy Act referred to in the preceding clause, or under any amendment thereto, or under any other applicable bankruptcy act which shall give relief substantially the same as that afforded by Chapter IX of said act; or (v) consent to the appointment of a receiver of the whole or any substantial part of the applicable Project; or (vi) 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 Energy Northwest or of the whole or any substantial part of the applicable Project.

Upon the occurrence of an Event of Default described in the preceding paragraphs, and in each and every such case, so long as such Event of Default shall not have been remedied, unless the principal of all the related Electric Revenue Bonds shall have already become due and payable, the Trustee may, and upon the written request of the owners of not less than 25% of all related Electric Revenue Bonds then outstanding shall, proceed to enforce by such proceedings at law or in equity as it deems most effectual the rights of related Bondholders, and either the Trustee (by notice in writing to Energy Northwest), or the owners of not less than 25% in principal amount of the related Electric Revenue Bonds outstanding (by notice in writing to Energy Northwest and the Trustee), may declare the principal of all the related Electric Revenue Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable; provided, however, that so long as any of the Prior Lien Bonds of the related Project remain outstanding, no such declaration may be made unless the principal of all the Prior Lien Bonds of the related Project then outstanding, and the interest accrued thereon, shall have been declared to be due and payable immediately pursuant to Section 12.1 of Resolution No. 769, Section 11.1 of Resolution No. 640 or Section 11.1 of Resolution No. 775, as the case may be. The Trustee shall not be obligated to notify Energy Northwest of its intent to make such a declaration prior to making such declaration. The right of the Trustee or of the owners of not less than 25% in principal amount of the related Electric Revenue Bonds to make any such declaration, however, shall be subject to the condition that if, at any time after such declaration, but before the related Electric Revenue Bonds shall have matured by their terms, all overdue installments of interest upon the related Electric Revenue Bonds, together with interest on such overdue installments of interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee (including reasonable fees and expenses of counsel to the Trustee), and all other sums then payable by Energy Northwest under the related Electric Revenue Bond Resolution (except the principal of, and interest accrued since the next preceding Payment Date on, the related Electric Revenue Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the related Electric Revenue Bonds or under the related Electric Revenue Bond Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be cured or provision shall be made therefor, then and in every such case the owners of a majority in principal amount of the related Electric Revenue Bonds outstanding, by written notice to Energy Northwest and to the Trustee, may rescind such declaration and annul such default in its entirety, or, if the Trustee shall have acted itself, and if there shall not have been theretofore delivered to the Trustee written directions to the contrary by the owners of a majority in principal amount of the related Electric Revenue Bonds then outstanding, then any such declaration shall *ipso facto* be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any resulting right or power.

Notice to Bondholders of an Event of Default (Section 802)

The Trustee, within 25 days after the occurrence of an Event of Default, shall give to the Bondholders of the related Electric Revenue Bonds, in the manner provided in the applicable Electric Revenue Bond Resolution, notice of all defaults known to the Trustee, and shall give prompt written notice thereof to Energy Northwest, unless such defaults shall have been cured before the giving of such notice.

Accounting and Examination of Records After Default (Section 803)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and account of Energy Northwest relating to the related Project and all other records relating thereto shall at all times be subject to the inspection and use of the Trustee and any persons holding at least twenty-five percent (25%) of the principal amount of the related Electric Revenue Bonds outstanding and of their respective agents and attorneys or of any committee therefor.

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, Energy Northwest will continue to account, as a trustee of an express trust, for all revenues and other moneys, securities and funds pledged under the related Electric Revenue Bond Resolution.

Application of Revenues in an Event of Default (Section 804)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee (i) forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution, and (ii) subject to the provisions of the respective Prior Lien Resolutions as promptly as practicable after receipt thereof, all revenues of the related Project (provided that if other Parity Debt is outstanding Energy Northwest shall pay over to the Trustee the Trustee's pro rata share of such revenues).

Subject to the provisions of the Prior Lien Resolutions, respectively, during the continuance of an Event of Default, the revenues and other moneys of the related Project received by the Trustee shall be applied by the Trustee: first, to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the related Project, including the costs of decommissioning and site restoration, if any, and all other proper disbursements or liabilities made or incurred by the Trustee (including the fees and expenses of counsel to the Trustee); and second, to the then due and overdue payments into the related Debt Service Fund and the due and overdue payments on any related Parity Reimbursement Obligations and the due and overdue payments of any other obligation of Energy Northwest for which the Revenues are pledged on a parity with the pledge under Section 202(a) of the related Electric Revenue Bond Resolution pursuant to a Supplemental Electric Revenue Bond Resolution ("Other Parity Obligations"); and lastly, for any lawful purpose in connection with the related Project.

In the event that at any time the funds held by the Trustee shall be insufficient for the payment of the principal of, premium, if any, and interest then due on the related Electric Revenue Bonds and payments then due on any related Parity Reimbursement Obligations and Other Parity Obligations, such funds (other than funds held for the payment or redemption of particular Electric Revenue Bonds or Parity Reimbursement Obligations or Other Parity Obligations, including, without limiting the generality of the foregoing, amounts held in any Reserve Account for a particular Series of Electric Revenue Bonds) and all revenues of Energy Northwest and other moneys received or collected for the benefit or for the account of owners of the Electric Revenue Bonds and any Parity Reimbursement Obligations and Other Parity Obligations by the Trustee shall be applied as follows:

(1) Unless the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the applicable Project and all other proper disbursements or liabilities made or incurred by the Trustee;

Second, to the payment to the persons entitled thereto of all installments of interest then due on the related Electric Revenue Bonds (including any interest on overdue principal) in the order of the maturity of such installments, earliest maturities first, and on any related Parity Reimbursement Obligations and Other Parity Obligations and if the amounts available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Third, to the payment to the persons entitled thereto of the principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at the time of such payment without preference or priority of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, and if the amounts available therefor shall not be sufficient to pay in full any principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at such time, then to the payment thereof, ratably, according to the amounts due respectively for principal and redemption premium, without any discrimination or preference.

(2) If the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the related Project and all other proper disbursements or liabilities made or incurred by the Trustee; and

Second, to the payment of the principal and interest then due and unpaid upon the related Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Whenever moneys are to be applied as described in the preceding paragraphs, such moneys shall be applied by the Trustee, at such times, and from time to time, as it in its sole discretion shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future.

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its monies, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

Remedies Not Exclusive (Section 809)

No remedy by the terms of either of the Electric Revenue Bond Resolutions conferred upon or reserved to the owners of the related Electric Revenue Bonds is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to any other remedy given to the owners of the related Electric Revenue Bonds or now or hereafter existing at law or in equity or by statute.

Waivers of Default (Section 810)

No delay or omission of any owner of Electric Revenue Bonds to exercise any right or power arising upon the occurrence of a default hereunder, including an Event of Default, will impair any right or power or shall be construed to be a waiver of any such default or to be an acquiescence therein. Every power and remedy given by this Article to the Article to the Trustee or to the owners of Electric Revenue Bonds may be exercised from time to time and as often as may be deemed expedient by such Trustee or by such owners.

Prior to the declaration of acceleration of the Electric Revenue Bonds as provided in Section 801, the holders of a majority in principal amount of the Electric Revenue Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the holders of all the Electric Revenue Bonds waive any past default under this Resolution and its consequences, except a default described in paragraph (1), (2), (3) or (4) of Section 801. No such waiver will extend to any subsequent or other default or impair any right consequent thereon.

Supplemental Electric Revenue Bond Resolutions (Article IX)

Supplemental Electric Revenue Bond Resolutions Effective Without Consent of Owners of Electric Revenue Bonds. Energy Northwest, from time to time and at any time and without the consent or concurrence of any owner of any Electric Revenue Bond, may adopt a resolution amendatory of each Electric Revenue Bond Resolution or supplemental to each Electric Revenue Bond Resolution (i) for the purpose of providing for the issuance of Electric Revenue Bonds pursuant to the provisions of Article II of each Electric Revenue Bond Resolution; or (ii) if the provisions of such Supplemental Electric Revenue Bond Resolutions shall not adversely affect the rights of the owners of the Electric Revenue Bonds of each Series or, if a Series consists of two or more subseries, of each subseries thereof, affected by such Supplemental Electric Revenue Bond Resolutions then outstanding, for any one or more of the following purposes:

(1) to make any changes or corrections in the Electric Revenue Bond Resolutions as to which Energy Northwest shall have been advised by counsel that the same are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provision or omission or mistake or manifest error contained in the Electric

Revenue Bond Resolutions, or to insert in the Electric Revenue Bond Resolutions such provisions clarifying matters or questions arising under the Electric Revenue Bond Resolutions as are necessary or desirable;

(2) to add additional covenants and agreements of Energy Northwest for the purpose of further securing the payment of the Electric Revenue Bonds;

(3) to surrender any right, power or privilege reserved to or conferred upon Energy Northwest by the terms of the Electric Revenue Bond Resolutions;

(4) to confirm as further assurance any lien, pledge or charge, or the subjection to any lien, pledge, or charge, created or to be created by the provisions of the Electric Revenue Bond Resolutions;

(5) to grant or to confer upon the owners of the Electric Revenue Bonds any additional rights, remedies, powers, authority or security that lawfully may be granted to or conferred upon them, or to grant to or to confer upon the Trustee for the benefit of the owners of the Electric Revenue Bonds any additional rights, duties, remedies, powers, authority or security or to provide for one or more Credit Facilities;

(6) to make any appointment or to add any provision, in either case, required or permitted by the Electric Revenue Bond Resolutions to be so made or added pursuant to a Supplemental Electric Revenue Bond Resolution;

(7) to enter into Payment Agreements; and

(8) to make any other change which Energy Northwest deems necessary or desirable and which does not adversely affect the rights of the Bondholders.

Supplemental Electric Revenue Bond Resolutions Effective With Consent of Bondholders. At any time, Supplemental Electric Revenue Bond Resolutions may be adopted subject to consent by Bondholders in accordance with and subject to the provisions of each Electric Revenue Bond Resolution, which Supplemental Electric Revenue Bond Resolutions, upon the filing with the Trustee of a copy thereof certified by an authorized officer of Energy Northwest and upon compliance with the provisions of Article X of each Electric Revenue Bond Resolution, shall become fully effective in accordance with its terms as provided in said Article.

Powers of Amendment (Section 1002)

Any modification or amendment of the Electric Revenue Bond Resolutions or of the rights and obligations of Energy Northwest and of the owner of the Electric Revenue Bonds thereunder, in any particular, may be made by Supplemental Electric Revenue Bond Resolutions, with the written consent given as provided in each Electric Revenue Bond Resolution, (i) of the owners of not less than a majority in principal amount of the related Electric Revenue Bonds outstanding at the time such consent is given and (ii) in case less than all of the several Series of Electric Revenue Bonds or, if any Series consists of two or more subseries, the subseries thereof, then outstanding are affected by the modification or amendment, of the owners of not less than a majority in principal amount of the Electric Revenue Bonds of such Series or subseries, as the case may be, so affected and outstanding at the time such consent is given; except that if such modification or amendment will, by its terms, not take effect so long as any Electric Revenue Bonds of any specified like Series, subseries, if applicable, and maturity remain outstanding, the consent of the owners of such Electric Revenue Bonds shall not be required and such Electric Revenue Bonds shall not be deemed to be outstanding for the purpose of any calculation of outstanding Electric Revenue Bonds under this provision of each Electric Revenue Bond Resolution. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any outstanding Electric Revenue Bond or of any installment of interest thereon or a reduction in the principal amount or the redemption price thereof or in the rate of interest thereon without the consent of the owner of such Electric Revenue Bond, or shall reduce the percentages or otherwise affect the classes of Electric Revenue Bonds the consent of the owners of which is required to effect any such modification or amendment, or permit a preference or priority of any Electric Revenue Bond over any other or shall change or modify any of the rights or obligations of any fiduciary without its written assent thereto. For the purposes of this provision of each Electric Revenue Bond Resolution, a Series or subseries, as the case may be, shall be deemed to be affected by a modification or amendment of each Electric Revenue Bond Resolution if the same adversely affects or diminishes the rights of the owners of Electric Revenue Bonds of such Series or subseries, respectively. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment of the Electric Revenue Bonds of any particular Series, Subseries, if applicable, or maturity would be affected by any modification or amendment of the Electric Revenue Bond Resolutions and any such determination shall be binding and conclusive on Energy Northwest and all owners of Electric Revenue Bonds. For the purposes of this Section, the owners of the Electric Revenue Bonds may include the initial owners thereof, regardless of whether such Electric Revenue Bonds are being held for immediate resale.

Defeasance (Article XI)

Except as otherwise provided in each Supplemental Electric Revenue Bond Resolution authorizing the issuance of variable rate Electric Revenue Bonds, the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in such Electric Revenue

Bond Resolutions, shall be fully discharged and satisfied as to any related Electric Revenue Bond and such related Electric Revenue Bond shall no longer be deemed to be outstanding hereunder,

(i) when such related Electric Revenue Bond shall have been canceled, or shall have been surrendered for cancellation or is subject to cancellation, or shall have been purchased by the Trustee from moneys held under the related Electric Revenue Bond Resolutions; or

(ii) as to any related Electric Revenue Bond not canceled or surrendered for cancellation or subject to cancellation or so purchased, when payment of the principal of and premium, if any, on such related Electric Revenue Bond, plus interest on such principal to the due date thereof (whether such due date be by reason of maturity or upon redemption or prepayment, or otherwise) either (A) shall have been made or caused to be made in accordance with the terms thereof, or (B) shall have been provided for by irrevocably depositing with the trustee or a paying agent for such Electric Revenue Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment or (2) Defeasance Obligations maturing, or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will insure the availability of sufficient moneys to make such payment, or a combination thereof, whichever Energy Northwest deems to be in its best interest, and all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to the Electric Revenue Bond with respect to which such deposit is made shall have been paid or the payment thereof provided for to the satisfaction of the Trustee and said paying agents. In addition, with respect to the Series 2004-B Taxable, the following provisions shall also be required for such Bonds to be deemed no longer outstanding under the respective Electric Revenue Bond Resolution: (1) Energy Northwest shall have delivered to the Trustee either (a) a ruling from the Internal Revenue Service to the effect that the Holders of such Bonds will not recognize income, gain or loss for federal income tax purposes as a result of Energy Northwest's exercise of its defeasance option and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such option had not been exercised, or (b) an opinion of counsel to the same effect as the ruling described in clause (a) of this paragraph; and (2) Energy Northwest has delivered an opinion of counsel stating that the deposit shall not result in Energy Northwest or the Trustee becoming or being deemed to be an "investment company" under the Investment Company Act of 1940.

At such time as an Electric Revenue Bond shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, such Electric Revenue Bond shall no longer be secured by or entitled to the benefits of the related Electric Revenue Bond Resolution, except for the purposes of any payment from such moneys or Defeasance Obligations.

Notwithstanding the foregoing, in the case of an Electric Revenue Bond which is to be redeemed or otherwise prepaid prior to its stated maturity, no deposit under clause (B) of subparagraph (ii) above shall constitute such payment, discharge and satisfaction as aforesaid until such Electric Revenue Bond shall have been irrevocably designated for redemption or prepayment and proper notice of such redemption or prepayment shall have been previously published in accordance with each Electric Revenue Bond Resolution or in accordance with the provisions of the Supplemental Electric Revenue Bond Resolutions which authorized the issuance of the Electric Revenue Bonds being refunded or provision satisfactory to the Trustee shall have been irrevocably made for the giving of such notice.

Any such moneys so deposited with the trustee or paying agents for the Electric Revenue Bonds as provided in the Electric Revenue Bond Resolutions may at the direction of Energy Northwest also be invested and reinvested in Defeasance Obligations, maturing in the amounts and times as hereinbefore set forth. All income from all Defeasance Obligations in the hands of the trustee or paying agents which is not required for the payment of the Electric Revenue Bonds and interest and premium thereon with respect to which such moneys shall have been so deposited, shall be paid to Energy Northwest for deposit in the respective General Revenue Funds. Likewise, whenever all of the Electric Revenue Bonds of a Series shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, as aforesaid, the amounts, if any, remaining on deposit to the credit of the Reserve Accounts established for such Series shall be paid to Energy Northwest for deposit in the respective General Revenue Funds.

Any provision contained in the Electric Revenue Bond Resolutions to the contrary notwithstanding, all moneys and Defeasance Obligations set aside and held in trust for the payment of Electric Revenue Bonds shall be applied to and used solely for the payment of the particular Electric Revenue Bond with respect to which such moneys and Defeasance Obligations have been so set aside in trust.

Notwithstanding anything in the Electric Revenue Bond Resolutions to the contrary, if moneys or Defeasance Obligations have been deposited or set aside with the trustee or a paying agent for the payment of a specific Electric Revenue Bond and such Electric Revenue Bond shall be deemed to have been paid and to be no longer outstanding, but such Electric Revenue Bond shall not have in fact been actually paid in full, no amendment to the provisions of either of the Electric Revenue Bond Resolutions shall be made without the consent of the owner of each Electric Revenue Bond affected thereby.

Energy Northwest may at any time surrender to the Trustee for cancellation by it any Electric Revenue Bonds previously executed and delivered, which Energy Northwest may have acquired in any manner whatsoever, and such Electric

Revenue Bonds upon such surrender for cancellation shall be deemed to be paid and no longer outstanding under either of the Electric Revenue Bond Resolutions.

Neither the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions, nor any Supplemental Resolutions authorizing Parity Reimbursement Obligations and/or Other Parity Obligations, shall be discharged or satisfied with respect to such Parity Reimbursement Obligations or Other Parity Obligations, respectively, until such Parity Reimbursement Obligations shall have been paid in accordance with their terms.

Summary of the Supplemental Electric Revenue Bond Resolutions

Debt Service Account. Each Supplemental Electric Revenue Bond Resolution creates and establishes a special trust account of the Debt Service Fund which shall be held by the Trustee subject to the lien of the related Project's Electric Revenue Bond Resolution. The Debt Service Accounts shall be funded as provided in the related Electric Revenue Bond Resolution and amounts therein shall be used and applied as provided in the related Supplemental Electric Revenue Bond Resolution and in the related Electric Revenue Bond Resolution.

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APPENDIX H-2

SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS

The following summary is a brief outline of certain provisions contained in the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution as amended and supplemented (collectively referred to in this Appendix H-2 as the "Prior Lien Resolutions"), and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Prior Lien Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the respective Bond Fund Trustees and Paying Agents for the Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds and Project 3 Prior Lien Bonds (together, the "Prior Lien Bonds").

Subsequent Series of Prior Lien Bonds

Under the Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, Energy Northwest has covenanted with the owners from time to time of the Electric Revenue Bonds not to issue any further Prior Lien Bonds or any other bonds, warrants or obligations having a lien on Revenues on a parity with the Prior Lien Bonds.

Effect of Amendments Adopted September 14, 1989 and March 16, 1990 (Project 1, Columbia and Project 3)

Amendments Effective Immediately: Resolution No. 548 (the "Project 1 1989A Supplemental Resolution") and Resolution No. 549 (the "Project 3 1989A Supplemental Resolution" and, together with the Project 1 1989A Supplemental Resolution, the "1989A Supplemental Resolutions"), each adopted by the Executive Board of Energy Northwest on September 14, 1989, and Resolution No. 583 (the "Columbia 1990A Supplemental Resolution"), adopted by the Executive Board of Energy Northwest on March 15, 1990, amend the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution, respectively, to add certain property disposition covenants. The 1989A Supplemental Resolutions and Columbia 1990A Supplemental Resolution also amend the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution to add a covenant of Energy Northwest that it shall take such actions as are necessary to enforce the provisions of the Assignment Agreements relating to Project 1, Columbia and Project 3, respectively, and certain agreements of Bonneville with respect to the disposition of the respective Project 1, Columbia and Project 3 properties following a termination of such Projects. Each of the Prior Lien Resolutions was also amended to add a covenant by Energy Northwest with respect to the Prior Lien Bonds issued prior to the date of adoption of the amending resolution to the effect that, in exercising any rights it may have to redeem such Bonds at par under the extraordinary redemption provisions relating to such Bonds in the event of a termination of the related Project, it will only redeem such Bonds from the proceeds, if any, received by Energy Northwest from the sale or other disposition of Project 1, Columbia or Project 3 properties, as the case may be, and, in the case of the Project 1 and Project 3 Prior Lien Bonds, from amounts, if any, then on deposit in the Construction Fund established under the Project 1 Prior Lien Resolution or the Project 3 Prior Lien Resolution, as the case may be. Such amendments became effective immediately upon adoption of the respective 1989A Supplemental Resolutions and Columbia 1990A Supplemental Resolution in accordance with their terms.

Springing Amendments: The Project 1 1989A Supplemental Resolution effects various amendments to the Project 1 Prior Lien Resolution which became effective when the Project 1 Prior Lien Bonds issued prior to the adoption of the Project 1 1989A Supplemental Resolution ceased to be outstanding. The Columbia 1990A Supplemental Resolution effects various amendments to the Columbia Prior Lien Resolution which became effective when the Columbia Prior Lien Bonds issued prior to the adoption of the Columbia 1990A Supplemental Resolution ceased to be outstanding. The Project 3 1989A Supplemental Resolution effects various amendments to the Project 3 Prior Lien Resolution which became effective when the Project 3 Prior Lien Bonds issued prior to the adoption of the Project 3 1989A Supplemental Resolution ceased to be outstanding.

The 1989A Supplemental Resolution and the Columbia 1990A Supplemental Resolution amend the Prior Lien Resolutions to add the defined terms summarized below to each such Prior Lien Resolution, such amendments to become effective as described above. As used below, the term "Bonds" refers to the Project 1 Prior Lien Bonds, the Columbia Prior Lien Bonds and the Project 3 Prior Lien Bonds.

> *"Credit Facility"* means a letter of credit, revolving credit agreement, standby bond purchase agreement, surety bond, insurance policy or similar obligation, arrangement or instrument issued by a bank, insurance company or other financial institution which provides for payment of all or a portion of the Principal Installments or interest due on any Series of Bonds or provides funds for the purchase of such Bonds or portions thereof.
>
> *"Qualified Credit Facility"* means, with respect to any series of Bonds or a portion thereof, a Credit Facility (A) which provides funds for (1) the direct payment of the Principal Installments of and interest on such Bonds, when due or (2) the payment of the Principal Installments of and interest on such Bonds in the event amounts otherwise pledged to the payment thereof are not available when due(in each case, regardless of whether such Credit Facility provides funds for another purpose) and (B) which (1) requires Energy Northwest to directly reimburse the issuer of such Credit Facility for amounts paid thereunder and (2) provides that such obligation is a Parity Reimbursement Obligation.

"Financial Guaranties" means one or more of the following: (A) letters of credit, lines of credit or other similar credit facilities issued by banking institutions the senior long-term debt obligations of which (or the holding company of any such banking institution) are (at the time of issue of such credit facility) rated in one of the two highest rating categories by Moody's Investors Service Inc. ("Moody's") and by Standard & Poor's Credit Markets Services ("S&P"); or (B) a policy or policies of insurance or surety bond or bonds issued by municipal bond insurers the obligations insured by which are eligible for a rating in one of the two highest rating categories by Moody's and by S&P; in each case providing for the payment of sums for the payment of Principal Installments of and interest on Bonds in the manner provided in the supplemental resolution authorizing such Bonds; and providing further that any such Financial Guaranty must be drawn upon, on a date which is at least thirty days prior to the expiration date of such Financial Guaranty, in an amount equal to the deficiency which would exist if the Financial Guaranty expired unless a substitute Financial Guaranty is required prior to such expiration date.

"Parity Reimbursement Obligation" means a Reimbursement Obligation, the payment of which is secured by a lien on the revenues, receipts, profits, income and other moneys pledged by the applicable Prior Lien Resolution on a parity with the lien created by the applicable Prior Lien Resolution in favor of Bonds issued thereunder. "Reimbursement Obligation" means the obligation of Energy Northwest to directly reimburse the issuer of a Credit Facility for amounts paid by such issuer thereunder.

"Principal Installment" means, as of any date of calculation and with respect to any Series of Bonds, so long as any such Bonds are outstanding, (A) the principal amount (including (1) any amount designated in, or determined pursuant to, the applicable supplemental resolution as the "principal amount" with respect to any Bonds which do not pay full current interest for all or any part of their term, and (2) the principal amount of any Parity Reimbursement Obligation) of such Series of Bonds due on a certain future date for which no sinking fund payments for the retirement of term bonds in advance of maturity have been established, or (B) the unsatisfied balance of any such sinking fund payments due on a certain future date for bonds of such series, or (C) if such future dates coincide as to different bonds of such series, the sum of such principal amount of Bonds and of such unsatisfied balance of sinking fund payments due on such future date.

The 1989A Supplemental Resolutions and Columbia 1990A Supplemental Resolution also affect the amendments to the Prior Lien Resolutions, which take effect as described above and which are summarized below.

The Prior Lien Resolutions are amended to: (i) authorize the issuance of Project 1, Columbia and Project 3 Prior Lien Bonds, respectively, payable from and secured by a Qualified Credit Facility and to permit the creation of Parity Reimbursement Obligations with respect to such Qualified Credit Facility payable on a parity with the related Net Billed Bonds and secured by an equal charge and lien on the revenues of the related Net Billed Project; (ii) provide that no amount need be deposited in the Reserve Account for any Prior Lien Bonds the principal of and interest on which is payable from and secured by a Qualified Credit Facility; (iii) provide that the deposit required to be made into the reserve account established for any Prior Lien Bonds may be satisfied by depositing Financial Guaranties in such reserve account; and (iv) provide that, in connection with the issuance of any refunding Project 1, Columbia or Project 3 Prior Lien Bonds, the amount, if any, required to be deposited in the reserve account established for such Bonds may be accomplished through the transfer of all or a portion of the moneys on deposit in the reserve account for the Project 1, Columbia or Project 3 Prior Lien Bonds (as the case may be) being refunded, whether or not such Bonds being refunded constitute all of the remaining outstanding Project 1, Columbia or Project 3 Prior Lien Bonds of a Series of such Bonds.

Resolution No. 565 and Resolution No. 566, each adopted by the Executive Board of Energy Northwest on December 7, 1989, and the Columbia 1990A Supplemental Resolution provide that, unless Financial Guaranty Insurance Company consents to the deposit of a Financial Guaranty in a reserve account, certain requirements must be met as a condition to any such deposit.

The Prior Lien Resolutions are also amended to provide, in connection with the issuance of refunding Project 1, Columbia or Project 3 Prior Lien Bonds, that amounts on deposit in the Interest Account representing interest accrued on refunded Project 1, Columbia or Project 3 Prior Lien Bonds (as the case may be) no longer deemed outstanding under the applicable Prior Lien Resolution may be withdrawn on the date such refunded Bonds cease to be outstanding and may be transferred to a separate trust fund established with the applicable Bond Fund Trustee or Paying Agent to pay when due interest on such refunded Bonds.

The Prior Lien Resolutions each provide that upon the happening of an Event of Default thereunder, and prior to such Event of Default having been remedied, either the applicable Bond Fund Trustee or the holders of not less than 20% in principal amount of the Project 1 Prior Lien Bonds, the Columbia Prior Lien Bonds or the Project 3 Prior Lien Bonds (as the case may be) then outstanding under the applicable Resolution may declare the principal of all the Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable. The Prior Lien Resolutions are amended to provide that the right of the applicable Bond Fund Trustee, or the holders of not less than 20% in principal amount of the related Prior Lien Bonds then outstanding, to declare the principal of all the related Prior Lien Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, as aforesaid, shall be available only if there shall occur and be continuing an Event of Default involving failure to pay amounts required to be paid into the related Revenue Fund, failure to pay principal of, premium, if any, or interest on the related Prior Lien Bonds or the bankruptcy or insolvency of Energy Northwest, or appointment of a receiver for the properties of the related Net Billed Project. See "Events of Default; Remedies" in this Appendix H-2 for a description of the Events of Default under the Prior Lien Resolutions and the Events of Default to which such amendments are applicable.

The Prior Lien Resolutions are also amended to clarify the right of Energy Northwest, in the event of a termination of Project 1, Columbia or Project 3, to sell or otherwise dispose of the properties of such terminated Project without first having to provide for the payment of the outstanding related Prior Lien Bonds.

In addition, the Project 1 1989A Supplemental Resolution and Columbia 1990A Supplemental Resolution amend the Project 1 Prior Lien Resolution and Columbia Prior Lien Resolution, respectively, to permit the adoption of supplemental resolutions, with the consent of the Bond Fund Trustee for the related Project, to cure any ambiguity or defect or inconsistent provision in the related Prior Lien Resolution or to insert such provisions clarifying matters or questions arising under the related Prior Lien Resolution as are necessary or desirable and, in the case of the Project 1 Prior Lien Resolution, either (1) not contrary to or inconsistent with such Prior Lien Resolution as theretofore in effect or (ii) not adverse to the rights and interests of the holders of the Project 1 Prior Lien Bonds or, in the case of the Columbia Prior Lien Resolution, not adverse to the rights and interests of the holders of the Columbia Prior Lien Bonds.

In connection with the refunding of the balance of the Project 1 and 3 Prior Lien Bonds issued prior to 1989, and in connection with the Columbia Prior Lien Bonds issued prior to 1990, the Project 1, Columbia and Project 3 Prior Lien Resolutions were amended to provide that the applicable Bond Fund Trustee shall, after making the required transfers of investment income to the applicable Revenue Fund, transfer the balance remaining on deposit in the applicable Interest Account, Principal Account, Bond Retirement Account and the Reserve Account, as directed by Energy Northwest, to the trustee of the applicable trust fund established to pay the principal of, and redemption premium, if any, and interest on the related Prior Lien Bonds, for deposit into such separate trust fund or, to the extent not so transferred, to the applicable bond fund trustee of each bond fund established for bonds issued from and after 1989 and 1990, respectively, pursuant to the applicable Prior Lien Resolution and then outstanding, for deposit to the credit of the interest account therein in the same proportion as the amount of interest due on the next succeeding interest payment date of such series of bonds bears to the total amount of interest due on such next succeeding interest payment date on all such series of additional bonds.

Construction Fund

The Project 1 Prior Lien Resolution establishes an Energy Northwest Project No. 1 Construction Fund and a Construction Interest Account and a Fuel Account therein, to be held by the Construction Fund Trustee. U.S. Bank National Association is Construction Fund Trustee under the Project 1 Prior Lien Resolution.

The Project 3 Prior Lien Resolution establishes an Energy Northwest Nuclear Project No. 3 Construction Fund to be held in trust by Energy Northwest.

The Project 3 Prior Lien Resolution provides that if working capital is not provided for by September 1, 1982, or if a Reserve and Contingency Fund requirement of $3,000,000 is not provided for by the Date of Commercial Operation, through revenues received pursuant to the Project 3 Net Billing Agreements, such amounts will be provided from Project 3 Prior Lien Bond proceeds, including moneys then on deposit in the Project No. 3 Construction Fund.

The proceeds of sale of subsequent Series of Project 1 or Project 3 Prior Lien Bonds issued to pay the Cost of Construction of the related Net Billed Project will be applied as follows:

(a) An amount equal to the interest accrued on such Series of Prior Lien Bonds from their date to the date of their delivery to the initial purchasers will be credited, in the case of Project 1 Prior Lien Bonds, to the interest Account in the Construction Fund for Project 1 or, in the case of Project 3 Prior Lien Bonds, to the Interest Account in the Bond Fund for Project 3;

(b) Except as otherwise authorized pursuant to the amendments described under "Effect of Amendments Adopted September 4, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" above, an amount equal to the largest amount of interest required to be paid on such Series of Prior Lien Bonds during any six-month period from the date of such Bonds to the final maturity date thereof will be credited to the Reserve Account in the Bond Fund for the related Net Billed Project if such amount is not funded by revenues of the related Net Billed Project;

(c) In the case of Project 1 Prior Lien Bonds, such amounts as Energy Northwest determines will be credited to the Fuel Account in the Construction Fund for Project 1; and

(d) The balance of such Bond proceeds will be deposited in the Construction Fund for the respective Net Billed Project, provided a part of such proceeds may be deposited in the Revenue Fund for such Net Billed Project as required for additional working capital.

Moneys in each Net Billed Project Construction Fund are to be used to pay Energy Northwest's Cost of Construction of such Net Billed Project, which includes costs of constructing and acquiring such Project, obtaining permits and licenses and acquiring property and fuel, trustees' and paying agents' fees, taxes and insurance premiums, the cost of engineering services and administrative and overhead expenses of Energy Northwest allocable to the acquisition and construction of such Project. The cost of acquiring fuel for each Net Billed Project will be paid from such Project's Fuel Fund.

Each Prior Lien Resolution prescribes certain procedures designed to safeguard payments or transfers from each Net Billed Project's Construction Fund, including, among others, certificates by the appropriate Construction Engineer and, for Project 1, a detailed itemization by Energy Northwest of the amounts to be paid and the purposes thereof.

Moneys remaining in a Net Billed Project Construction Fund after providing for the payment of all Costs of Construction, in the case of Project 1, and all of Energy Northwest's Costs of Construction, in the case of Project 3, and after required payments, if any, to other accounts, are to be transferred to such Project's Bond Retirement Account.

Other Funds Established by the Prior Lien Resolutions; Flow of Revenues

In addition to the Construction Fund, each Prior Lien Resolution establishes a separate Revenue Fund, Fuel Fund, and Reserve and Contingency Fund. Each Prior Lien Resolution also establishes a Bond Fund (including an Interest Account, a Principal Account, a Bond Retirement Account, and a Reserve Account) from which payments are to be made with respect to the related Prior Lien Bonds issued to pay the Cost of Construction of the related Net Billed Project. A separate bond fund, including an interest account, a principal account (if applicable), a bond retirement account (if applicable), and a reserve account, is required to be established for each Series of additional Prior Lien Bonds issued for purposes other than paying the Cost of Construction of the related Net Billed Project. All such funds are to be held by Energy Northwest, except for the Project No. 1 Construction Fund, the Project No. 1 Bond Fund, the Columbia Bond Fund, the Project No. 3 Bond Fund and the separate bond funds (collectively, the "Bond Funds"), each of which is to be held by the appropriate Bond Fund Trustee.

Project No. 1 Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Project 1 are to be paid into the Project No. 1 Revenue Fund. Moneys in such Revenue Fund are to be used solely for the purpose of making required payments into the Hanford Project Revenue Fund, paying the principal of and premium, if any, and interest on the Project 1 Prior Lien Bonds, paying for the costs of operating and maintaining Project 1, making required payments into the Project No. 1 Fuel Fund and Reserve and Contingency Fund, making repairs, renewals, replacements, additions, betterments and improvements to and extensions of Project 1, and paying all other charges or obligations against the revenues pledged to the Project No. 1 Revenue Fund.

Project No. 1 Bond Funds: From the revenues theretofor paid into the Project No. 1 Revenue Fund, Energy Northwest is to pay monthly into the Project No. 1 Bond Funds, after making the required payments, if any, to the Hanford Project Revenue Fund, fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on the Project 1 Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Project No. 1 Reserve Account, for each Series of outstanding Project 1 Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Project 1 Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six-month period from the date of such Bonds to the final maturity date thereof. Energy Northwest is required to maintain the required amount in the reserve accounts by payments from the Project No. 1 Revenue Fund. See "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" in this Appendix H-2 for a description of amendments to certain of the provisions described above.

Project No. 1 Fuel Fund: Beginning on the Date of Commercial Operation, all payments for fuel for Project 1 will be made from the Project No. 1 Fuel Fund. After the Date of Commercial Operation, after making the required payments, if any, into the Hanford Project Revenue Fund and Project No. 1 Bond Funds and after paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Project 1, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Project No. 1 Revenue Fund to said Fuel Fund the following amounts:

(i) the amount included in the annual budget for fuel adopted pursuant to the Project 1 Project Agreement,

(ii) all amounts received by Energy Northwest as fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(iii) any additional amounts necessary to avoid a deficiency in the Project No. 1 Fuel Fund.

Upon termination of Project 1 in accordance with the Project 1 Project Agreement, the Project 1 Prior Lien Resolution required that the unobligated balance in the Project No. 1 Fuel Fund be transferred into the Project No. 1 Revenue Fund.

Project No. 1 Reserve and Contingency Fund: Since September 25, 1980, Energy Northwest has been required to pay monthly out of the Project No. 1 Revenue Fund into the Project No. 1 Reserve and Contingency Fund, after making the required payments, if any, into the Hanford Project Revenue Fund and the Project No. 1 Bond Funds, paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Project 1, including taxes or payments in lieu thereof, and making the required payments in the Project No. 1 Fuel Fund, an amount equal to 10% of the aggregate of the amounts required to be paid during such month into the Interest, Principal and Bond Retirement Accounts in the Project No. 1 Bond Funds.

Moneys in the Reserve and Contingency Fund shall be used from time to time to make up any deficiencies in the Interest Account, Principal Account or Bond Retirement Account in the Bond Fund for which funds are not available in the Construction Fund or the Reserve Account, or to make up any deficiencies in the interest account, principal account or bond retirement account in any bond fund established for additional Bonds issued pursuant to the Project 1 Prior Lien Resolution for which funds are not available in any construction fund or reserve account for such additional Bonds, and any such moneys in the Reserve and Contingency Fund are hereby pledged as additional payments into the Bond Fund or any such bond fund to the extent required to make up any such deficiencies. To the extent not required for any such deficiency, moneys in the Reserve and Contingency Fund may be applied on and after the Date of Commercial Operation to any one or more of the following:

(1) to pay the cost of renewals and replacements to Project 1;

(2) to pay the cost of normal additions to and to extensions of Project 1; and

(3) to pay extraordinary operation and maintenance costs, including extraordinary costs of Fuel and the cost of preventing or correcting any unusual loss or damage (including major repairs) to Project 1.

If, as of June 30 in any year, moneys and value of Investment Securities in the Reserve and Contingency Fund shall exceed the amount of the then commitments or obligations incurred by the then requirements of Energy Northwest for any of the foregoing purposes, plus $3,000,000, the amount of such excess shall be paid into the Reserve Account and the reserve account for any series of additional Bonds issued pursuant to the Project 1 Prior Lien Resolution to the extent of any deficiency therein (pro rata in proportion to the respective deficiencies if such excess is insufficient to satisfy all such deficiencies) and the balance, if any, of such excess shall be paid as of June 30 into the Revenue Fund.

Columbia Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Columbia are to be paid into the Columbia Revenue Fund. Moneys in the Columbia Revenue Fund are to be used for the purpose of making required payments into the Columbia Bond Funds, paying for the costs of operating and maintaining Columbia, making required payments into the Columbia Fuel Fund and the Columbia Reserve and Contingency Fund, paying the costs of repairs, renewals, replacements, additions, betterments and improvements to and extensions of Columbia, and paying all other charges or obligations against the revenues pledged to the Columbia Revenue Fund.

Columbia Bond Funds: From the revenues theretofore paid into said Revenue Fund, Energy Northwest is to pay monthly into the Columbia Bond Funds fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on Columbia Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Columbia Reserve Account, for each Series of outstanding Columbia Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Columbia Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six-month period from the date of such Bonds to the final maturity date thereof. The reserve account requirement for additional Columbia Prior Lien Bonds shall be deposited from Columbia Prior Lien Bond proceeds or revenues available therefor at the time of issuance of such Bonds. Energy Northwest is required to maintain the required amount in said reserve accounts by payments from the Columbia Revenue Fund. See "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" in this Appendix H-2 for a description of amendments to certain of the provisions described above, which amendments will become effective in the future.

Columbia Fuel Fund: All payments for fuel for Columbia have been made, since the Date of Commercial Operation of Columbia, and will continue to be made, from the Columbia Fuel Fund. After making the required payments into the Columbia Bond Funds and after paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Columbia, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Columbia Revenue Fund to said Fuel Fund the following amounts:

(i) the amount included in the annual budget for fuel adopted pursuant to the Columbia Net Billing Agreement,

(ii) all amounts received by Energy Northwest from fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(iii) any additional amounts necessary to avoid a deficiency in said Fuel Fund.

If Columbia is terminated pursuant to the Columbia Project Agreement, the Columbia Prior Lien Resolution requires that the balance in the Columbia Fuel Fund be transferred into the Columbia Revenue Fund.

Columbia Reserve and Contingency Fund: Since September 25, 1977, Energy Northwest has been required to pay monthly out of the Columbia Revenue Fund into the Columbia Reserve and Contingency Fund, after making the required payments into the Columbia Bond Funds, paying or making provisions for payment of the reasonable and necessary costs of operating and maintaining Columbia, and making the required payments into the Columbia Fuel Fund, an amount equal to 10%

of the aggregate of the amounts required to be paid during such month from said Revenue Fund into the Interest, Principal, and Bond Retirement Accounts in the Columbia Bond Funds.

Project No. 3 Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Project 3 are to be paid into the Project No. 3 Revenue Fund. Moneys in the Project No. 3 Revenue Fund are to be used for the purpose of making required payments into the Project No. 3 Bond Funds, paying for Energy Northwest's costs of operating and maintaining Project 3, making required payments into the Project No. 3 Fuel Fund and the Project No. 3 Reserve and Contingency Fund, paying Energy Northwest's costs of repairs, renewals, replacements, additions, betterments and improvements to and extensions of Project 3, and paying all other charges or obligations against the revenues pledged to the Project No. 3 Revenue Fund.

Project No. 3 Bond Funds: From the revenues theretofore paid into said Revenue Fund, Energy Northwest is to pay monthly into the Project No. 3 Bond Funds fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on the Project 3 Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Project No. 3 Reserve Account, for each Series of outstanding Project 3 Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Project 3 Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six month period from the date of such Bonds to the final maturity date thereof. Energy Northwest is required to maintain the required amount in the reserve accounts by payments from the Project No. 3 Revenue Fund. See "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" in this Appendix H-2 for a description of amendments to certain of the provisions described above.

Project No. 3 Fuel Fund: Beginning on the Date of Commercial Operation, all payments for fuel for Project No. 3 will be made from the Project No. 3 Fuel Fund. After the Date of Commercial Operation, after making the required payments into the Project No. 3 Bond Funds and after paying or making provision for payment of Energy Northwest's reasonable and necessary costs of operating and maintaining Project 3, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Project No. 3 Revenue Fund to said Fuel Fund the following amounts:

(1) the amount included in the annual budget for fuel adopted pursuant to the Project 3 Project Agreement,

(2) all amounts received by Energy Northwest from fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(3) any additional amounts necessary to avoid a deficiency in said Fuel Fund.

Upon termination of Project 3 pursuant to the Project 3 Project Agreement, the Project 3 Prior Lien Resolution required that the unobligated balance in the Project No. 3 Fuel Fund be transferred into the Project No. 3 Revenue Fund.

Project No. 3 Reserve and Contingency Fund: Since September 25, 1982, Energy Northwest has been required to pay monthly out of the Project No. 3 Revenue Fund into the Project No. 3 Reserve and Contingency Fund, after making the required payments into the Project No. 3 Bond Funds, paying or making provision for payment of Energy Northwest's reasonable and necessary costs of operating and maintaining Project 3, and making the required payments into the Project No. 3 Fuel Fund, an amount equal to 10% of the aggregate of the amounts required to be paid during such month from said Revenue Fund into the Interest, Principal and Bond Retirement Accounts in the Project No. 3 Bond Funds.

Moneys in each Net Billed Project's Reserve and Contingency Fund are required to be used to make up deficiencies in the respective Project's Bond Funds for which funds are not available in the respective Project's Construction Fund or Reserve Accounts. To the extent not required for any such deficiency, moneys in each Project's Reserve and Contingency Fund may be used after the respective Date of Commercial Operation for any one or more of the following purposes:

(i) To pay the cost of renewals, replacements and normal additions to and extensions of such Net Billed Project; and

(ii) To pay extraordinary operation and maintenance costs, including extraordinary costs of fuel and the cost of preventing or correcting any unusual loss or damage (including major repairs) to such Project.

Investment of Funds: The term "Investment Securities", as defined in the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution, means (i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America; (ii) general obligation bonds of any state of the United States rated by a nationally recognized bond rating agency in either of the two highest rating categories assigned by such rating agency; (iii) bonds, debentures, notes or participation certificates issued by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-Import Bank of the United States, Federal Land Banks or the Federal National Mortgage Association or of any agency of or corporation wholly owned by the United States of America; (iv) in the case of the Project 1 Prior Lien Resolution and the Columbia Prior Lien Resolution, Public Housing Bonds or Project Notes issued by Public Housing Authorities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof and, in the case of the Project 3

Prior Lien Resolution, New Housing Authority Bonds or Project Notes issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof; (v) bank time deposits evidenced by certificates of deposit, and, in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, by bankers' acceptances, in each case, issued by any bank, trust company or national banking association authorized to do business in the State of Washington, which is a member of the Federal Reserve System, provided that the aggregate of such bank time deposits and, in the case of the Project 1 or Project 3 Prior Lien Resolution, bankers' acceptances issued by any bank, trust company or banking association do not exceed at any time, in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, fifty per centum (50%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and, in the case of the Columbia Prior Lien Resolution, twenty-five per centum (25%) of the total of the capital stock and surplus of such bank, trust company or banking association; (vi) in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, bank time deposits evidenced by certificates of deposit, and bankers' acceptances, issued by any bank, trust company or national banking association authorized to do business in any state of the United States of America other than the State of Washington, which is a member of the Federal Reserve System, provided that the aggregate of such bank time deposits and bankers' acceptances issued by any bank, trust company or banking association do not exceed at any one time twenty-five per centum (25%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and provided further that such capital stock, surplus and undivided profits shall not be less than Fifty Million Dollars ($50,000,000); and (vii) in the case of the Project 1 Prior Lien Resolution, evidences of indebtedness issued by any corporation organized and existing under the laws of any state of the United States of America rated by any nationally recognized bond rating agency in either of the two highest rating categories assigned by such rating agency.

Moneys in the Project No. 1 Revenue Fund not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at or prior to the estimated time for disbursement of such moneys. Moneys in the Project No. 1 Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Project No. 1 Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 1 Prior Lien Bonds). Moneys in the Project No. 1 Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 1 Prior Lien Bonds). Moneys in the Project No. 1 Construction Fund are to be invested by the Project No. 1 Construction Fund Trustee in Investment Securities maturing or redeemable within five years of the date of investment.

Moneys in the Columbia Revenue Fund not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at or prior to the estimated time for the disbursement of such moneys. Moneys in the Columbia Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Columbia Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Columbia Prior Lien Bonds). Moneys in the Columbia Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within two years from the date of investment with respect to the Fuel Fund and within seven years from the date of investment with respect to the Reserve and Contingency Fund (but in each case maturing prior to the final maturity date of the Columbia Prior Lien Bonds).

Moneys in the Project No. 3 Revenue Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable at or prior to the estimated time for the disbursement of such moneys. Moneys in the Project No. 3 Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Project No. 3 Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 3 Prior Lien Bonds). Moneys in the Project No. 3 Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 3 Prior Lien Bonds). Moneys in the Project No. 3 Construction Fund are to be invested in Investment Securities maturing or redeemable within seven years of the date of investment.

In the case of certain Refunding Bonds, the supplemental resolutions authorizing such Refunding Bonds provide that moneys on deposit in the related Project's reserve account in the bond fund established for such Refunding Bonds and not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at the option of the holder thereof on or prior to the final maturity date of such Refunding Bonds.

Excess Moneys: Moneys and the value of Investment Securities in each Project's Reserve and Contingency Fund in excess of $3,000,000 plus the commitments or obligations incurred by, or the requirements of Energy Northwest for, any of the purposes for which such Reserve and Contingency Funds may be used constitute "excess moneys" in respect of such Fund; and moneys and the value of Investment Securities described in clauses (i) through (iv) in this Appendix H-2 under "Investment of Funds" in each Project's Reserve Accounts in excess of the amounts required to be maintained in said Reserve Accounts constitute "excess moneys" in respect of such Accounts.

If as of any June 30, excess moneys exist in the Reserve and Contingency Fund for any Net Billed Project, such moneys shall be paid proportionately into such Project's Reserve Accounts, to the extent of any deficiency therein, and the balance of such excess moneys shall be paid into such Project's Revenue Fund.

If as of any June 30, excess moneys exist in the Reserve Account in the Bond Fund for any Net Billed Project, such moneys shall be paid proportionately into such Project's other reserve accounts in the separate bond funds, to the extent of any deficiency therein, and the balance of such excess moneys shall be paid into such Project's Revenue Fund.

If as of June 30, there shall exist in any Net Billed Project's Revenue Fund, after giving effect to any transfer of excess moneys from such Project's Reserve Account and Reserve and Contingency Fund to such Fund, an amount which exceeds Energy Northwest's required amount of working capital for such Project, the amount of such excess is to be applied to reduce annual power costs under the related Net Billing Agreements. The "required amount of working capital" shall be $3,000,000 or, in the case of the Project 1 and 3 Prior Lien Resolutions, such greater amount, and, in the case of the Columbia Prior Lien Resolution, such lesser amount (but not less than $2,000,000) or such greater amount, as may be decided upon by Energy Northwest and Bonneville with the approval of the Consulting Engineer. In addition, if Energy Northwest and Bonneville agree, all or any part of such excess over required working capital for a Net Billed Project may be applied to the making of repairs, renewals, replacements, additions, betterments and improvements to, and extensions of, such Project, the purchase or redemption of Bonds for such Project or for other purposes in connection with such Project.

Certain Covenants

Certain covenants of Energy Northwest with the holders of the Prior Lien Bonds are summarized as follows:

The Hanford Project: Under the Project 1 Prior Lien Resolution, Energy Northwest covenants that it (a) will not issue any evidences of indebtedness under Resolution No. 178 so long as the obligations of said resolution are satisfied under the Project 1 Prior Lien Resolution, (b) will discharge all of its duties and obligations under Resolution No. 178, (c) will make all payments and deposits to be made under the provisions of Resolution No. 178 from moneys to be provided pursuant to the Project 1 Prior Lien Resolution if and to the extent such obligations are not otherwise provided for, (d) will, on each December 31, apply any excess of amounts in the Hanford Project Revenue Fund over the required amount of working capital to reduce the amounts required by the Project 1 Prior Lien Resolution to be deposited in the Hanford Project Revenue Fund, and (e) will not amend Resolution No. 178 in any manner which adversely affects the rights of Bondholders under the Project 1 Prior Lien Resolution.

The Net Billed Projects: Energy Northwest covenants that it will, subject to the Project Agreements for each of the Net Billed Projects, complete construction of the Net Billed Projects at the earliest practicable time, operate such Projects and the business in connection therewith in an efficient manner and at reasonable cost, maintain such Projects in good condition and make all necessary and proper repairs, renewals, replacements, additions, extensions and betterments to such Projects.

Rates: Energy Northwest covenants that it will dispose of all capability of and power and energy from Project 1 solely for the benefit and account of such Project and pursuant to the provisions of the Project 1 Net Billing Agreements; and Energy Northwest covenants that it will maintain and collect rates and charges for capability, power and energy and other services, facilities and commodities sold, furnished or supplied through such Project, which will be adequate, whether or not the generation or transmission of power by such Project is suspended, interrupted or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to make the required payments into the Hanford Project Revenue Fund, (ii) to pay the expenses of operating and maintaining Project 1, (iii) to make the required payments into the Project No. 1 Bond Funds and (iv) to make the payments required into certain funds under the Project 1 Prior Lien Resolution.

Energy Northwest covenants that it will dispose of all capability of and power and energy from Columbia solely for the benefit and account of such Project and pursuant to the provisions of the Columbia Net Billing Agreements; and Energy Northwest covenants that it will maintain and collect rates and charges for power and energy, including capability, and other services, facilities, and commodities sold, furnished, or supplied through such Project, which will be adequate, whether or not the generation or transmission of power by the Project is suspended, interrupted, or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to pay the expenses of operating, maintaining and repairing such Project, (ii) to make the required payments into the Columbia Bond Funds, and (iii) to make the payments required into certain funds under the Columbia Prior Lien Resolution.

Energy Northwest covenants that it will dispose of all capability of and power and energy from Project 3 solely for the benefit and account of such Project and pursuant to the provisions of the Project 3 Net Billing Agreements and the Project 3 Power Sales Agreement; and Energy Northwest covenants that it will maintain and collect rates and charges for power and energy, including capability, and other services, facilities and commodities sold, furnished or supplied by such Project, which will be adequate, whether or not the generation or transmission of power by the Project is suspended, interrupted or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to pay Energy Northwest's expenses of operating and maintaining such Project, (ii) to make the required payments into the Project No. 3 Bond Funds, and (iii) to make the required into certain funds under the Project 3 Prior Lien Resolution.

Net Billing Agreements and Project Agreements: Energy Northwest covenants that it will not voluntarily consent to any amendment or permit any rescission of or take any action under or in connection with any of the Project Agreements or the Net Billing Agreements which will in any manner impair or adversely affect the rights of Energy Northwest or any of its Bondholders, or take any action under or in connection with the Net Billing Agreements which will reduce the payments provided for therein.

Disposition of Properties: Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Project 1 except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Hanford Project Revenue Fund and the Project No. 1 Bond Funds sufficient to retire all of the Project 1 Prior Lien Bonds and the Hanford Project Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Project 1 and any real or personal property comprising a part thereof which is unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Project 1, in which case $100,000 of the moneys received therefor is to be transferred to the Project No. 1 Reserve and Contingency Fund and the balance is to be paid proportionately into the Project No. 1 Bond Retirement Accounts unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Project No. 1 Reserve and Contingency Fund or the Project No. 1 Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys received therefor are to be paid proportionately into the Project No. 1 Bond Retirement Accounts.

Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Columbia except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Columbia Bond Funds sufficient to retire all of the Columbia Prior Lien Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Columbia and any real or personal property comprising a part thereof which a Consulting Engineer has certified that such properties are not unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Columbia, in which case $50,000 of the moneys received therefor is to be transferred to the Columbia Reserve and Contingency Fund and the balance is to be paid proportionately into the Columbia Bond Retirement Accounts unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Columbia Reserve and Contingency Fund or the Columbia Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys received therefor are to be paid proportionately into the Columbia Bond Retirement Accounts.

Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Project 3 except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Project No. 3 Bond Funds sufficient to retire all of the Project 3 Prior Lien Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Project 3 and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Project 3, in which case $100,000 of the moneys received therefor is to be transferred to the Project No. 3 Reserve and Contingency Fund and the balance is to be paid proportionately into the Project No. 3 Bond Retirement Accounts, unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Project No. 3 Reserve and Contingency Fund or the Project No. 3 Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys, received therefor are to be paid proportionately into the Project No. 3 Bond Retirement Accounts.

In the case of Project 1 and Project 3, notwithstanding the provisions of clauses (b) and (c) above with respect to said Project, moneys received by Energy Northwest prior to the Date of Commercial Operation for a Net Billed Project as a result of any sale, lease, transfer or other disposition specified therein shall be transferred to such Project's Construction Fund.

See "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" in this Appendix H-2 for a description of covenants relating to the disposition of properties of a Net Billed Project following termination of such Project.

Insurance: Energy Northwest covenants that it will keep Project 1, Columbia and Project 3 insured, to the extent such insurance is available at reasonable cost, against risks of direct physical loss or damage to or destruction of each such Project, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and against accidents, casualties, or negligence, including liability insurance and employer's liability, in the case of Project 1 and Project 3, at least to the extent that similar insurance is usually carried by electric utilities operating like properties.

In the event that any loss or damage to the properties of any Net Billed Project occurs during the period of construction of such Project, Energy Northwest is to transfer the insurance proceeds, if any, in respect of such loss or damage to such Project's Construction Fund; any insurance proceeds received by Energy Northwest in respect of such loss or damage occurring thereafter are to be transferred into such Project's Reserve and Contingency Fund, or, in the case of insurance covering loss or damage to fuel, to such Project's Fuel Fund.

Books of Account: Energy Northwest covenants that it will keep proper books of account, showing Project 1, Columbia and Project 3 as separate utility systems in accordance with the rules and regulations of the Division of Municipal Corporations of the State Auditor's office of the State of Washington and in accordance with the Uniform System of Accounts prescribed by the Federal Power Commission. Such books of account are to be audited annually by a firm of independent certified public accountants of national reputation. Bondholders may obtain copies of the annual financial statements showing the financial condition of the Project and the annual audit report by sending a written request therefor to Energy Northwest.

Consulting Engineer: Energy Northwest will retain a nationally recognized independent consulting engineer or engineering firm to render continuous engineering counsel in the operation of each Net Billed Project. In addition to his other duties, the Consulting Engineer shall prepare, not later than 18 months after the respective Date of Commercial Operation of each Net Billed Project, and each three years thereafter, a report for each such Project based upon a survey of such Project and the operation and maintenance thereof. Each report is to show, among other things, whether Energy Northwest has satisfactorily performed and complied with certain covenants in the related Prior Lien Resolution. The Consulting Engineer is also required to report to the respective Bond Fund Trustee and Energy Northwest upon the economic soundness and feasibility of all contemplated renewals, replacements, additions, betterments and improvements to, and extensions of, Project 1, Columbia and Project 3 involving an expenditure of, in the case of Projects 1 and 3, $500,000 or more, and, in the case of Columbia, $100,000 or more. The Consulting Engineer is also required to file annually a certificate with each Bond Fund Trustee describing the insurance then in effect for the respective Project and stating whether or not such insurance complies with the requirements of the related Prior Lien Resolution. In the event of any loss or damage, in the case of Projects 1 and 3, in excess of $500,000, and, in the case of Columbia, in excess of $100,000, whether or not covered by insurance, the Consulting Engineer is to ascertain the amount of such loss or damage and deliver to Energy Northwest a certificate setting forth the amount and nature of such loss or damage, together with recommendations as to whether or not such loss or damage should be replaced or repaid. Copies of any such triennial report, annual certificate as to insurance or certificate in respect of any such loss or damage will be sent to Bondholders filing with Energy Northwest written requests therefor.

Events of Default; Remedies

Under each Prior Lien Resolution, the happening of one or more of the following events constitutes an Event of Default: (i) default in the performance of any obligation with respect to payments into the respective Revenue Fund; (ii) default in the payment of the principal of and premium, if any, or default for 30 days in the payment of interest on any of the respective Prior Lien Bonds or any sinking fund installment on any Project 1 or Columbia Prior Lien Bonds; (iii) default for 90 days in the observance and performance of any other of the covenants, conditions and agreements of Energy Northwest in the respective Prior Lien Resolution; (iv) the sale or conveyance of any properties of the respective Net Billed Project except as permitted by the respective Net Billed Resolution or the voluntary forfeiture of any license, franchise, permit or other privilege necessary or desirable in the operation of such Project; (v) the entering by any court of competent jurisdiction of an order, judgment or decree (a) appointing a receiver, trustee or liquidator for Energy Northwest or the whole or any substantial part of the respective Net Billed Project, (b) approving a petition filed against Energy Northwest under Federal bankruptcy laws, or (c) assuming custody or control of Energy Northwest or of the whole or any substantial part of the respective Net Billed Project under the provisions of any other law for the relief or aid of debtors and such order, judgment or decree shall not be vacated or set aside or stayed (or, in case custody or control is assumed by said order, such custody or control shall not be otherwise terminated), within 60 days from the date of the entry of such order, judgment or decree; or (vi) Energy Northwest (a) admits in writing its inability to pay its debts incurred in the ownership and operation of the respective Net Billed Project generally as they become due, (b) files a petition in bankruptcy or seeking a composition of indebtedness, (c) consents to the appointment of a receiver of its creditors, (d) consents to the appointment of a receiver of the whole or any substantial part of the respective Net Billed Project, (e) files a petition or an answer seeking relief under Federal bankruptcy laws, or (f) consents 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 Energy Northwest or of the whole or any substantial part of the respective Net Billed Project.

If an Event of Default shall have occurred and shall not have been remedied, the respective Bond Fund Trustee or the holders of not less than 20% in principal amount of the respective Prior Lien Bonds then outstanding under the related Prior Lien Resolution, may declare the principal of all such Bonds and the interest accrued thereon to be immediately due and payable, but such declaration may be annulled under certain circumstances.

As described in this Appendix H-2 under "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)," the 1989A Supplemental Resolutions and Columbia 1990A Supplemental Resolution amend the Prior Lien Resolutions to provide that the applicable Bond Fund Trustee or the holders of not less than 20% in principal amount of Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds (as the case may be) shall have the right to declare the Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds immediately due and payable only upon the occurrence and continuance of an Event of Default described in clauses (i), (ii), (v), or (vi) in the second preceding paragraph. Such amendments became effective in the case of the Project 1 and Project 3 Prior Lien Resolutions when the Project 1 and Project 3 Prior Lien Bonds issued prior to the adoption of the 1989A Supplemental Resolutions ceased to be outstanding and may become effective in the future in the case of the Columbia Prior Lien Resolution, as described under "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)."

After the occurrence of an Event of Default and prior to the curing of such Event of Default, the Bond Fund Trustee of the Net Billed Project in default may, to the extent permitted by law, take possession and control of such Net Billed Project and operate and maintain the same, prescribe rates for capability or power sold or supplied through the facilities of such Project, collect the gross revenues resulting from such operation and perform all of the agreements and covenants contained in any contract which Energy Northwest is then obligated to perform. Such gross revenues, after payment of reasonable and proper charges, expenses and liabilities paid or incurred by the Bond Fund Trustee and operating expenses of the related Net Billed Project, and, in the case of Project 1, after additional payment of the amounts required by the Project 1 Prior Lien Resolution to be paid into the Hanford Project Revenue Fund, shall be applied to the payment of principal of and interest on the defaulting Net Billed Project's Bonds. Each Prior Lien Resolution provides that, in the event that at any time the funds held by the applicable Bond Fund Trustee and the Paying Agents for Prior Lien Bonds in default shall be insufficient for the payment of the principal of and premium, if any, and interest then due on such Prior Lien Bonds, such funds (other than funds held for the payment or redemption of particular Bonds which have theretofore become due at maturity or by call for redemption) and all revenues and other moneys received or collected for the benefit or for the account of holders of such Bonds by the applicable Bond Fund Trustee shall be applied as follows:

(1) Unless the principal of all such Bonds shall have become or have been declared due and payable,

First, to the payment of all installments of interest then due in the order of the maturity of such installments and, if the amount available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon; and

Second, to the payment of the unpaid principal and premium, if any, of any such Bonds which shall become due, whether at maturity or by call for redemption, in the order of their due dates and, if the amount available shall not be sufficient to pay in full all amounts due on any date, then to the payment thereof ratably, according to the amounts of principal and premium, if any, due on such date.

(2) If the principal of all of such Bonds shall have become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon such Bonds without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any Bond over any other Bond, ratably, according to the amounts of principal and interest due.

After all sums then due in respect of such Bonds have been paid, and after all Events of Default have been cured or secured to the satisfaction of the defaulting Net Billed Project's Bond Fund Trustee, such Bond Fund Trustee is required to relinquish possession and control of such Net Billed Project to Energy Northwest.

The Prior Lien Resolutions empower each Bond Fund Trustee to file proofs of claims for the benefit of the holders of the defaulting Net Billed Project's Bonds in bankruptcy, insolvency or reorganization proceedings and to institute suit for the collection of sums due and unpaid in connection with such Bonds, to enforce specific performance of covenants contained in the Prior Lien Resolution governing the Net Billed Project in default or to obtain injunctive or other appropriate relief for the protection of the holders of such Net Billed Bonds.

The holders of a majority in principal amount of the defaulting Net Billed Project's Prior Lien Bonds at the time outstanding have the right to direct the time, method and place of conducting any proceeding for any remedy available to the defaulting Net Billed Project's Bond Fund Trustee, or exercising any trust or power conferred upon such Bond Fund Trustee, but such Bond Fund Trustee must be provided with reasonable security and indemnity and also may decline to follow any such direction if it shall be advised by counsel that the action or proceeding so directed may not lawfully be taken or if it in good faith determines that the action or proceeding so directed would involve it in personal liability or that the action or proceeding so directed would be unjustly prejudicial to the holders of such Bonds not parties to such direction. No holder of any Prior Lien Bond has any right to institute suit to enforce any provision of the respective Prior Lien Resolution or the execution of any trust thereunder (except to enforce the payment of principal or interest installments as they mature), unless the respective Bond Fund Trustee has been requested by the holders of not less than 20% in aggregate principal amount of such Bonds then outstanding to exercise the powers granted it by such Resolution or to institute such suit and unless such Bond Fund Trustee has failed or refused to comply with the aforesaid request.

Amendments; Supplemental Resolutions

Any amendment to a Prior Lien Resolution in any particular, except the percentage of Bondholders the approval of which is required to approve such amendment, may be made by Energy Northwest with the consent of the holders of $66^2/_3$% in principal amount of the Prior Lien Bonds issued pursuant to such Resolution then outstanding and with the consent of the holders of $66^2/_3$% in principal amount of such outstanding Bonds which are adversely affected by an amendment which does not equally affect all other such outstanding Bonds, provided that no such amendment shall permit a change in the date of payment of principal of or any installment of interest on any such Bond or a reduction in the principal or redemption price thereof or the rate of interest thereon without the consent of each such Bondholder so affected.

Without the consent of Bondholders, Energy Northwest may adopt supplemental resolutions for any of, but not limited to, the following purposes: (i) to authorize the issuance of subsequent Series of Project 1, Columbia or Project 3 Prior Lien Bonds; (ii) to add to the covenants of Energy Northwest contained in, or to surrender any rights reserved to or conferred upon it by, a Prior Lien Resolution; (iii) to add to the restrictions contained in a Prior Lien Resolution upon the issuance of additional indebtedness; (iv) to confirm as further assurance any pledge under a Prior Lien Resolution of the revenues of the respective Net Billed Project or other moneys; (v) otherwise to modify any of the provisions of a Prior Lien Resolution (but no such modification may be effective while any of the Prior Lien Bonds theretofore issued pursuant to such Resolution are outstanding); or (vi) to cure any ambiguity or defect or inconsistent provision in such Resolution or to insert such provisions clarifying matters or questions arising under such Resolution as necessary or desirable in the event any such modifications are not contrary to or inconsistent with such Resolution or, in the case of the Project 3 Prior Lien Resolution, not adverse to the rights and interests of the holders of the Project 3 Prior Lien Bonds, provided that the appropriate Bond Fund Trustee shall consent thereto.

As described in this Appendix H-2 under "Effect of Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)," the Project 1 1989A Supplemental Resolution, Columbia 1990A Supplemental Resolution and Project 3 1989A Supplemental Resolution amend the Project 1 Prior Lien Resolution, Columbia Prior Lien Resolution and Project 3 Prior Lien Resolution, respectively, to permit the adoption of supplemental resolutions for purposes described in clause (vi) of the preceding paragraph if such modifications are not adverse to the rights and interests of the holders of the Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds, as the case may be. Such amendments became effective in the case of the Project 1 and Project 3 Prior Lien Resolutions when the Project 1 and Project 3 Prior Lien Bonds issued prior to the adoption of the 1989A Supplemental Resolutions ceased to be outstanding and may become effective in the future in the case of the Columbia Prior Lien Resolution, as described under "Amendments Adopted September 14, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)."

Defeasance

The obligations of Energy Northwest under a Prior Lien Resolution shall be fully discharged and satisfied as to any related Prior Lien Bond, and such Bond shall no longer be deemed to be outstanding thereunder when payment of the principal of and the applicable redemption premium, if any, on such Bond plus interest to the due date thereof (a) shall have been made or caused to be made in accordance with the terms thereof, or (b) shall have been provided by irrevocably depositing with the Bond Fund Trustee or the Paying Agents therefor in trust solely for such payment (i) moneys sufficient to make such payments or (ii) Investment Securities described in clauses (i) through (iv) under "Investment of Funds" in this Appendix H-2 maturing as to principal and interest in such amounts and at such times as will insure the availability of sufficient moneys to make such payment, and, except for the purposes of such payment, such Bond shall no longer be secured by or entitled to the benefits of such Prior Lien Resolution; provided that, with respect to Prior Lien Bonds which by their terms may be redeemed or otherwise prepaid prior to the stated maturities thereof but are not then redeemable, no deposit under (b) above shall constitute such discharge and satisfaction unless such Bonds shall have been irrevocably called or designated for redemption on the first date thereafter such Bonds may be redeemed in accordance with the provisions thereof and notice of such redemption shall have been given or irrevocable provision shall have been made for the giving of such notice.

APPENDIX I

BOOK-ENTRY ONLY SYSTEM

The following information has been provided by The Depository Trust Company, New York, New York ("DTC"). Energy Northwest makes no representation regarding the accuracy or completeness thereof. Beneficial Owners (as hereinafter defined) should therefore confirm the following with DTC or the Participants (as hereinafter defined).

The 2004 Bonds will be available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the 2004 Bonds will not receive certificates representing their interests in the 2004 Bonds purchased, except as described below.

DTC will act as securities depository for the 2004 Bonds. The 2004 Bonds will be issued as fully-registered securities 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 2004 Bonds in the aggregate principal amount of such maturity, and will be deposited with DTC. If, however, the aggregate principal amount of any maturity exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount and an additional certificate will be issued with respect to any remaining principal amount of such issue.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds securities that its 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, also subsidiaries of DTCC, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to Participants are on file with the Securities and Exchange Commission.

Purchases of 2004 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for such 2004 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2004 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, but Beneficial Owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2004 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 2004 Bonds, except in the event that use of the book-entry system for the 2004 Bonds is discontinued.

To facilitate subsequent transfers, all 2004 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of 2004 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 2004 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2004 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of 2004 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2004 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the security documents. For example, Beneficial Owners of 2004 Bonds may wish to ascertain that the nominee holding the 2004 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners.

Redemption notices shall be sent to DTC. If less than all of the 2004 Bonds within an issue 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 2004 Bonds unless authorized by a Direct Participant in accordance with DTC's procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Issuer 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 the 2004 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the 2004 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 Energy Northwest or the Trustee 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, the Trustee, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Trustee, 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 2004 Bonds at any time by giving reasonable notice to Energy Northwest or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, such 2004 Bond certificates are required to be printed and delivered.

Energy Northwest may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, 2004 Bond certificates will be printed and delivered.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENT

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville will enter into a written agreement (the "Agreement") for the benefit of the holders and beneficial owners of the 2004 Bonds to provide continuing disclosure.

Definitions

In addition to the definitions set forth in the Net Billed Resolutions and the Agreement, which apply to any capitalized term used in the Agreement, the following capitalized terms shall have the following meanings:

"BPA Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2004 Bonds in the following tables in Appendix A under the heading "BONNEVILLE POWER ADMINISTRATION — BONNEVILLE FINANCIAL OPERATIONS — Historical Federal System Financial Data — Federal System Statement of Revenues and Expenses," "— Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" and "— Statement of Net Billing Obligations and Expenditures."

"Energy Northwest Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2004 Bonds in the following tables under the heading "ENERGY NORTHWEST — ENERGY NORTHWEST INDEBTEDNESS — Energy Northwest Revenue Bonds Outstanding as of May 1, 2004" and "ENERGY NORTHWEST — THE COLUMBIA GENERATING STATION — Annual Costs — Statement of Operations."

"Energy Northwest Fiscal Year" means the fiscal year ending each June 30 or, if such fiscal year end is changed, on such new date; provided that if the Energy Northwest Fiscal Year end is changed, Energy Northwest shall notify, in a timely manner, each NRMSIR and the SID, if any.

"FCRPS" means the Federal Columbia River Power System.

"FCRPS Fiscal Year" means the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year is changed, Bonneville shall notify, in a timely manner, each NRMSIR and the SID, if any.

"MSRB" means the Municipal Securities Rulemaking Board or any successor to its functions.

"NRMSIR" means a nationally recognized municipal securities information repository.

"Rule 15c2-12" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of this Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Agreement.

"SID" means a state information depository for the State of Washington, if any.

Financial Information

Bonneville. Bonneville agrees to provide to each NRMSIR and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2004:

(i) the BPA Annual Information for the FCRPS Fiscal Year; and

(ii) annual financial statements of the FCRPS for the FCRPS Fiscal Year, prepared in accordance with generally accepted accounting principles; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville shall notify Energy Northwest when such BPA Annual Information has been provided and when such financial statements have been provided.

Energy Northwest. Energy Northwest agrees to provide to each NRMSIR and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with Energy Northwest Fiscal Year ending June 30, 2004:

(i) the Energy Northwest Annual Information for the Energy Northwest Fiscal Year; and

(ii) annual financial statements of Energy Northwest for the Energy Northwest Fiscal Year, prepared in accordance with generally accepted accounting principles applicable to governmental entities; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not its audited annual financial statements, Energy Northwest shall provide its audited annual financial statements when and if they become available.

Cross-Reference. In lieu of providing the annual financial information and operating data described above, Bonneville and Energy Northwest may cross-refer to other documents provided to the NRMSIR, the SID, if any, or to the SEC and, if such document is a final official statement within the meaning of the Rule, available from the MSRB.

Notice of Failure to Provide Financial Information. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to each NRMSIR or to the MSRB and to the SID, if any, notice of its or Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above.

Material Events Notices

Energy Northwest 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 2004 Bonds, if material:

(i) Principal and interest payment delinquencies;

(ii) Non-payment related defaults;

(iii) Unscheduled draws on debt service reserves reflecting financial difficulties;

(iv) Unscheduled draws on credit enhancements reflecting financial difficulties;

(v) Substitution of credit or liquidity providers, or their failure to perform;

(vi) Adverse tax opinions or events affecting the tax-exempt status of the 2004-A Bonds;

(vii) Modifications to rights of 2004 Bond holders;

(viii) Optional, contingent or unscheduled calls of any 2004 Bonds other than scheduled sinking fund redemptions for which notice is given pursuant to Exchange Act Release 34-23856;

(ix) Defeasances;

(x) Release, substitution or sale of property securing repayment of the 2004 Bonds; and

(xi) Rating changes.

Solely for purposes of disclosure, and not intending to modify this undertaking, Energy Northwest advises with reference to items (iii) and (x) above that no debt service reserves or property secure payment of the 2004 Bonds.

Termination, Modification

The obligations of Bonneville and Energy Northwest to provide annual financial information and the obligation of Energy Northwest to provide notices of material events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2004 Bonds. Bonneville and Energy Northwest may amend the Agreement, and any provision of the Agreement may be waived, with an approving opinion of nationally recognized bond counsel and in accordance with the Rule.

In the event of any amendment or waiver of a provision of the Agreement, Bonneville and Energy Northwest shall describe such amendment in the next annual report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville or Energy Northwest, as applicable. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the same manner as for a material event, and (ii) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Remedies

The right of any Owner or Beneficial Owner of 2004 Bonds to enforce the provisions of the Agreement against Energy Northwest shall be limited to a right to obtain specific enforcement of Energy Northwest's obligations thereunder, and any failure by Energy Northwest to comply with the provisions of this Agreement shall not be an event of default under the Resolution or the Supplemental Resolution or with respect to the 2004 Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under the Agreement. Owners and Beneficial Owners of 2004 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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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Ambac

Financial Guaranty Insurance Policy

Ambac Assurance Corporation
One State Street Plaza, 15th Floor
New York, New York 10004
Telephone: (212) 668-0340

Obligor: Policy Number:

Obligations: Premium:

Ambac Assurance Corporation (Ambac), a Wisconsin stock insurance corporation, in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to The Bank of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of the Holders, that portion of the principal of and interest on the above-described obligations (the "Obligations") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor.

Ambac will make such payments to the Insurance Trustee within one (1) business day following written notification to Ambac of Nonpayment. Upon a Holder's presentation and surrender to the Insurance Trustee of such unpaid Obligations or related coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Holder the amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, Ambac shall become the owner of the surrendered Obligations and/or coupons and shall be fully subrogated to all of the Holder's rights to payment thereon.

In cases where the Obligations are issued in registered form, the Insurance Trustee shall disburse principal to a Holder only upon presentation and surrender to the Insurance Trustee of the unpaid Obligation, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee duly executed by the Holder or such Holder's duly authorized representative, so as to permit ownership of such Obligation to be registered in the name of Ambac or its nominee. The Insurance Trustee shall disburse interest to a Holder of a registered Obligation only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Obligation and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee, duly executed by the Holder or such Holder's duly authorized representative, transferring to Ambac all rights under such Obligation to receive the interest in respect of which the insurance disbursement was made. Ambac shall be subrogated to all of the Holders' rights to payment on registered Obligations to the extent of any insurance disbursements so made.

In the event that a trustee or paying agent for the Obligations has notice that any payment of principal of or interest on an Obligation which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from the Holder pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such Holder will be entitled to payment from Ambac to the extent of such recovery if sufficient funds are not otherwise available.

As used herein, the term "Holder" means any person other than (i) the Obligor or (ii) any person whose obligations constitute the underlying security or source of payment for the Obligations who, at the time of Nonpayment, is the owner of an Obligation or of a coupon relating to an Obligation. As used herein, "Due for Payment", when referring to the principal of Obligations, is when the scheduled maturity date or 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; and, when referring to interest on the Obligations, is when the scheduled date for payment of interest has been reached. As used herein, "Nonpayment" means the failure of the Obligor to have provided sufficient funds to the trustee or paying agent for payment in full of all principal of and interest on the Obligations which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Obligations prior to maturity. 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 Obligation, other than at the sole option of Ambac, nor against any risk other than Nonpayment.

In witness whereof, Ambac has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

President

AMBAC ASSURANCE CORPORATION
CORPORATE
SEAL
WISCONSIN

Anne G. Gill
Secretary

Effective Date:

Authorized Representative

THE BANK OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Authorized Officer of Insurance Trustee

Form No.: 2B-0012 (1/01)

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FGIC

Financial Guaranty Insurance Company
125 Park Avenue
New York, NY 10017
T 212·312·3000
T 800·352·0001

Municipal Bond
New Issue Insurance Policy

Issuer:	Policy Number:
	Control Number: 0010001
Bonds:	Premium:

Financial Guaranty Insurance Company ("Financial Guaranty"), a New York stock insurance company, in consideration of the payment of the premium and subject to the terms of this Policy, hereby unconditionally and irrevocably agrees to pay to U.S. Bank Trust National Association or its successor, as its agent (the "Fiscal Agent"), for the benefit of Bondholders, that portion of the principal and interest on the above-described debt obligations (the "Bonds") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer.

Financial Guaranty will make such payments to the Fiscal Agent on the date such principal or interest becomes Due for Payment or on the Business Day next following the day on which Financial Guaranty shall have received Notice of Nonpayment, whichever is later. The Fiscal Agent will disburse to the Bondholder the face amount of principal and interest which is then Due for Payment but is unpaid by reason of Nonpayment by the Issuer but only upon receipt by the Fiscal Agent, in form reasonably satisfactory to it, of (i) evidence of the Bondholder's right to receive payment of the principal or interest Due for Payment and (ii) evidence, including any appropriate instruments of assignment, that all of the Bondholder's rights to payment of such principal or interest Due for Payment shall thereupon vest in Financial Guaranty. Upon such disbursement, Financial Guaranty shall become the owner of the Bond, appurtenant coupon or right to payment of principal or interest on such Bond and shall be fully subrogated to all of the Bondholder's rights thereunder, including the Bondholder's right to payment thereof.

This Policy is non-cancellable for any reason. The premium on this Policy is not refundable for any reason, including the payment of the Bonds prior to their maturity. This Policy does not insure against loss of any prepayment premium which may at any time be payable with respect to any Bond.

As used herein, the term "Bondholder" means, as to a particular Bond, the person other than the Issuer who, at the time of Nonpayment, is entitled under the terms of such Bond to payment thereof. "Due for Payment" means, when referring to the principal of a Bond, the stated maturity date thereof or the date on which the same shall have been duly called for mandatory sinking fund redemption and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by mandatory sinking fund redemption), acceleration or other advancement of maturity and means, when referring to interest on a Bond, the stated date for payment of interest. "Nonpayment" in respect of a Bond means the failure of the Issuer to have provided sufficient funds to the paying agent for payment in full of all

FGIC

Financial Guaranty Insurance Company
125 Park Avenue
New York, NY 10017
T 212·312·3000
T 800·352·0001

Municipal Bond
New Issue Insurance Policy

principal and interest Due for Payment on such Bond. "Notice" means telephonic or telegraphic notice, subsequently confirmed in writing, or written notice by registered or certified mail, from a Bondholder or a paying agent for the Bonds to Financial Guaranty. "Business Day" means any day other than a Saturday, Sunday or a day on which the Fiscal Agent is authorized by law to remain closed.

In Witness Whereof, Financial Guaranty has caused this Policy to be affixed with its corporate seal and to be signed by its duly authorized officer in facsimile to become effective and binding upon Financial Guaranty by virtue of the countersignature of its duly authorized representative.

President

Effective Date: **Authorized Representative**

U.S. Bank Trust National Association, acknowledges that it has agreed to perform the duties of Fiscal Agent under this Policy.

Authorized Officer

FGIC

Financial Guaranty Insurance Company
125 Park Avenue
New York, NY 10017
T 212·312·3000
T 800·352·0001

Endorsement
To Financial Guaranty Insurance Company Insurance Policy

Policy Number: **Control Number:** 0010001

It is further understood that the term "Nonpayment" in respect of a Bond includes any payment of principal or interest made to a Bondholder by or on behalf of the issuer of such Bond which has been recovered from such Bondholder pursuant to the United States Bankruptcy Code by a trustee in bankruptcy in accordance with a final, nonappealable order of a court having competent jurisdiction.

NOTHING HEREIN SHALL BE CONSTRUED TO WAIVE, ALTER, REDUCE OR AMEND COVERAGE IN ANY OTHER SECTION OF THE POLICY. IF FOUND CONTRARY TO THE POLICY LANGUAGE, THE TERMS OF THIS ENDORSEMENT SUPERSEDE THE POLICY LANGUAGE.

In Witness Whereof, Financial Guaranty has caused this Endorsement to be affixed with its corporate seal and to be signed by its duly authorized officer in facsimile to become effective and binding upon Financial Guaranty by virtue of the countersignature of its duly authorized representative.

President

Effective Date: **Authorized Representative**

Acknowledged as of the Effective Date written above:

Authorized Officer
U.S. Bank Trust National Association, as Fiscal Agent

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