NEW ISSUE — BOOK-ENTRY ONLY

Series 2009-A Bonds and Series 2009-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, interest on the Series 2009-A Bonds and 2009-C 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"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Section 103 of the Internal Revenue Code of 1986 (the "1986 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2009-A Bonds and 2009-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. Special Tax Counsel expresses no opinion as to whether some or all interest on the Series 2009-A Bonds and the Series 2009-C Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. See "TAX MATTERS" herein.

Series 2009-B (Taxable) Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2009-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.

$370,555,000
Energy Northwest

$48,905,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-A
$116,425,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A
$116,055,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-A

$515,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)
$18,515,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable)
$970,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)

$69,170,000 Columbia Generating Station Electric Revenue Bonds, Series 2009-C

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

The Series 2009-A Bonds and a portion of the Series 2009-B (Taxable) Bonds are being issued for the purpose of refunding certain 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 Series 2009-C Bonds and a portion of the Columbia 2009-B (Taxable) Bonds are being issued to finance a portion of the costs of certain capital improvements to and operating costs for the Columbia Generating Station, as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2009-A Bonds, Series 2009-B (Taxable) Bonds and Series 2009-C Bonds (collectively, the "2009 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 2009 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 2009 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 2009 Bonds. Principal of the 2009 Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., Seattle, Washington, as Trustee for the 2009 Bonds. Interest on the 2009 Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2010, by check or draft of the Trustee. As long as Cede & Co. is the Registered Owner as nominee of DTC, payments on the 2009 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 2009 BONDS – GENERAL – Book-Entry System; Transferability and Registration" and Appendix I - "BOOK-ENTRY SYSTEM" herein.

Certain of the 2009 Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE 2009 BONDS - REDEMPTION" *herein.*

The 2009 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

("Bonneville") 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 2009 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 2009 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 Pages

The 2009 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Pepper PLLC, 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 to Bonneville. 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 2009 Bonds will be available for delivery through the facilities of DTC on or about April 15, 2009.

Citi **Goldman, Sachs & Co.**

J.P. Morgan **Prager, Sealy & Co., LLC** **Merrill Lynch & Co.**

April 2, 2009

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2009-A BONDS

$48,905,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2014	$ 23,710,000	4.00%	2.97%	29270CTY1
2015	6,635,000	3.25	3.25	29270CTZ8
2015	18,560,000	5.00	3.25	29270CUA1

$116,425,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2014	$ 6,000,000	3.00%	2.97%	29270CUB9
2015	3,350,000	4.00	3.25	29270CUC7
2015	37,880,000	5.00	3.25	29270CUD5
2016	6,325,000	4.00	3.46	29270CUE3
2016	3,675,000	5.00	3.46	29270CUF0
2017	5,000,000	5.00	3.68	29270CUG8
2018	8,780,000	4.00	3.88	29270CUH6
2018	45,415,000	5.00	3.88	29270CUJ2

$116,055,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2014	$ 11,940,000	5.00%	2.97%	29270CUK9
2015	12,750,000	5.00	3.25	29270CUL7
2018	16,365,000	5.00	3.88	29270CUM5
2018	75,000,000	5.25	3.88	29270CUN3

* CUSIP data herein are provided by Standard & Poor's CUSIP Service Bureau, a division of The McGraw-Hill Companies, Inc. The CUSIP numbers listed above are being provided solely for the convenience of Bondowners only at the time of issuance of the 2009 Bonds and Energy Northwest makes no representation with respect to such numbers and undertakes no responsibility for their accuracy now or at any time in the future. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2009 Bonds as a result of various subsequent actions, including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2009 Bonds.

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2009-B (TAXABLE) BONDS

$515,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2014	$ 515,000	4.59%	100%	29270CUX1

$18,515,000 Columbia Generating Station Electric Revenue and Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2014	$ 8,735,000	4.59%	100%	29270CUY9
2024**	9,780,000	6.80	100	29270CUZ6

$970,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2014	$ 970,000	4.59%	100%	29270CVA0

THE SERIES 2009-C BONDS

$69,170,000 Columbia Generating Station Electric Revenue Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2020	$ 14,305,000	5.00%	4.26%***	29270CUP8
2021	6,410,000	4.25	4.42	29270CUQ6
2021	8,610,000	5.00	4.42***	29270CUR4
2022	3,445,000	4.50	4.57	29270CUS2
2022	12,280,000	5.00	4.57***	29270CUT0
2023	11,765,000	5.00	4.74***	29270CUU7
2024	6,355,000	4.75	4.84	29270CUV5
2024	6,000,000	5.00	4.84***	29270CUW3

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* CUSIP data herein are provided by Standard & Poor's CUSIP Service Bureau, a division of The McGraw-Hill Companies, Inc. The CUSIP numbers listed above are being provided solely for the convenience of Bondowners only at the time of issuance of the 2009 Bonds and Energy Northwest makes no representation with respect to such numbers and undertakes no responsibility for their accuracy now or at any time in the future. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2009 Bonds as a result of various subsequent actions, including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2009 Bonds.

** Term Bond.

*** Priced to the par call date of July 1, 2019.

ENERGY NORTHWEST
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Executive Board Members

Sid W. Morrison, Chairman	Bill Gordon
Tom Casey, Vice Chairman	Dan G. Gunkel
David Remington, Secretary	Jack Janda
Kathleen Vaughn, Assistant Secretary	Lawrence Kenney
Edward E. Coates	Tim Sheldon
K.C. Golden	

Administrative Staff

Chief Executive Officer	Joseph V. Parrish
Vice President, Nuclear Generation/Chief Nuclear Officer	W. Scott Oxenford
Vice President, Technical Services	Sudesh K. Gambhir
Vice President, Operational Support	Dale K. Atkinson
Vice President, Energy/Business Services	John W. Baker
Vice President, Corporate Services/General Counsel/Chief Financial Officer	Albert E. Mouncer

Financial Advisor	*Bond Counsel*	*Trustee for the 2009 Bonds*
Public Financial Management, Inc.	Foster Pepper PLLC	The Bank of New York Mellon Trust Company, N.A.

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
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Administrator and Chief Executive Officer	Stephen J. Wright
Deputy Administrator	Steven G. Hickok
Chief Operating Officer	Anita J. Decker
Executive Vice President and General Counsel	Randy A. Roach
Executive Vice President and Chief Financial Officer	David J. Armstrong

Special Counsel and Special Tax 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 by, nor shall there be any sale of the 2009 Bonds to, 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.

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 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 2009 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2009 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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OFFICIAL STATEMENT

$370,555,000

ENERGY NORTHWEST

$48,905,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-A
$116,425,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A
$116,055,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-A

$515,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)
$18,515,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable)
$970,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)

$69,170,000 Columbia Generating Station Electric Revenue Bonds, Series 2009-C

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover pages hereof and the appendices hereto, in connection with the sale of the 2009 Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the 2009 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, proposes to issue $48,905,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2009-A (the "Project 1 2009-A Bonds"), $116,425,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A (the "Columbia 2009-A Bonds"), $116,055,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2009-A (the "Project 3 2009-A Bonds," and, together with the Project 1 2009-A Bonds and the Columbia 2009-A Bonds, the "Series 2009-A Bonds"), $515,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable) (the "Project 1 2009-B (Taxable) Bonds"), $18,515,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable) (the "Columbia 2009-B (Taxable) Bonds"), $970,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable) (the "Project 3 2009-B (Taxable) Bonds," and, together with the Project 1 2009-B (Taxable) Bonds and the Columbia 2009-B (Taxable) Bonds, the "Series 2009-B (Taxable) Bonds") and $69,170,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2009-C (the "Columbia 2009-C Bonds" or the "Series 2009-C Bonds"). The Series 2009-A Bonds, Series 2009-B (Taxable) Bonds and Series 2009-C Bonds are collectively referred to herein as the "2009 Bonds."

The Project 1 2009-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 on 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 2009-B (Taxable) Bonds (together with the Project 1 2009-A Bonds, the "Project 1 2009 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 2009 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 2009-A Bonds and a portion of the Columbia 2009-B (Taxable) 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 on 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 2009-C Bonds and a portion of the Columbia 2009-B (Taxable) Bonds are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution for the purpose of providing funds for a portion of the costs planned to be incurred during fiscal years 2009 and 2010 for certain capital improvements to and operating costs for the Columbia Generating Station. The Columbia 2009-A Bonds, the Columbia 2009-B (Taxable) Bonds and the Columbia 2009-C Bonds are referred to herein as the "Columbia 2009 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 2009-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") and certain indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution. The Project 3 2009-B (Taxable) Bonds (together with the Project 3 2009-A Bonds, the "Project 3 2009 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 2009 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 2009 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. In 2008, Energy Northwest added four new members: Clallam County, Whatcom County and Clark County Public Utility Districts and the City of Port Angeles. Energy Northwest now has 24 members, consisting of 20 public utility districts and the cities of Richland, Seattle, Tacoma and Port Angeles, 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"), with a net design electric rating of 1,157 megawatts. Energy Northwest also owns an operating hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), with a net design electric rating of 27.5 megawatts. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 63 turbines with a maximum generating capacity of approximately 96 megawatts. Energy Northwest also owns and has financial responsibility for four other nuclear electric generating projects that 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"). 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 ("DOE"), 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) for Projects 1 and 3 and Columbia, 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 31 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 eastern Montana, 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 almost twelve million people. Electric power sold by Bonneville accounts for more than one-third 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 2009 BONDS

The Project 1 2009 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2009 Bonds are secured, on a subordinated basis to the Project 1 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2009 Bonds are secured on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Columbia 2009 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2009 Bonds are secured, on a subordinated basis to the Columbia Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership and operation of Columbia. The Columbia 2009 Bonds are secured on a parity with the Columbia Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Project 3 2009 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2009 Bonds are secured, on a subordinated basis to the Project 3 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2009 Bonds are secured on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

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, so long as the Net Billing Agreements and the other Project agreements are in effect and no event of default is existing under the applicable Electric Revenue Bond Resolutions. 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 that will rank on a parity with the pledge of and lien on the revenues created by the Prior Lien Resolutions.

The 2009 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 2009 Bonds relating to that Project. Accordingly, the owners of the 2009 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 March 1, 2009, 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 the 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 have not been 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 by Participants 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.

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Direct Pay Agreements," in 2006 Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project pursuant to which Bonneville pays at least monthly all costs for each Net Billed Project directly to Energy Northwest. One effect of the Direct Payment Agreements is that each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. The Direct Pay Agreements do not amend the Net Billing Agreements. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

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" in this Official Statement.

DESCRIPTION OF THE 2009 BONDS

GENERAL

The 2009 Bonds are dated the date of delivery and mature on July 1 in the years and in the principal amounts shown on the inside cover pages of this Official Statement. The 2009 Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2010, at the rates shown on the inside cover pages of this Official Statement. Interest on the 2009 Bonds will be calculated based on a 360-day year, consisting of twelve 30-day months. The Bank of New York Mellon Trust Company, N.A., Seattle, Washington, has been appointed the Trustee, Paying Agent and Registrar for the 2009 Bonds (collectively, the "Trustee"). For so long as the 2009 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.

Book-Entry System; Transferability and Registration

The 2009 Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the 2009 Bonds will not receive certificates representing their interests in such 2009 Bonds purchased, except as described in Appendix I - "BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as securities depository for each Series of 2009 Bonds. As discussed in Appendix I - "BOOK-ENTRY SYSTEM," transfers of ownership interests in the 2009 Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the 2009 Bonds. Energy Northwest, the Trustee and any other person may treat the Registered Owner of any 2009 Bond as the absolute owner of such 2009 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 2009 Bond shall be overdue or not. All payments of or on account of interest or principal to any Registered Owner of any such 2009 Bond shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such 2009 Bond, to the extent of the sum or sums paid.

When 2009 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 DTC Participant (as defined in Appendix I - "BOOK-ENTRY SYSTEM") or to any person on behalf of whom a DTC Participant holds an interest in the 2009 Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2009 Bonds, (2) the delivery to any DTC Participant or any other person, other than a Registered Owner as shown on the Bond Register, of any notice with respect to the 2009 Bonds, including any notice of redemption, (3) the payment to any DTC 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 2009 Bonds, (4) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2009 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 2009 Bond is registered, as the holder and absolute owner of such 2009 Bond for the purpose of payment, giving notices of redemption and other matters.

Discontinuation of Book-Entry Transfer System

If Energy Northwest determines to discontinue the book-entry system of transfer, Energy Northwest is required to execute, authenticate and deliver at no cost to the beneficial owners of the 2009 Bonds, 2009 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2009 Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the 2009 Bonds will be payable by check or draft mailed to the persons in whose names such 2009 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date; 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 2009 Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. Principal of the 2009 Bonds is payable at the designated office of the Trustee. If the book-entry transfer system for the 2009 Bonds is discontinued, registered ownership of any 2009 Bond may be transferred or exchanged by surrendering such 2009 Bond to the Trustee, with the assignment form appearing on the 2009 Bond duly executed. The Trustee shall not be required to transfer any 2009 Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

<u>Series 2009-A Bonds</u>. The Series 2009-A Bonds are not subject to redemption prior to their stated maturities.

<u>Series 2009-B (Taxable) Bonds</u>. The Series 2009-B (Taxable) Bonds are subject to redemption prior to maturity at the election of Energy Northwest, in whole or in part, on any date, at a Redemption Price equal to the greater of (i) 100% of the principal amount thereof plus accrued and unpaid interest to the redemption date on the Series 2009-B (Taxable) Bonds to be redeemed, or (ii) the sum of the present values of the remaining scheduled payments of principal and interest payments on the Series 2009-B (Taxable) Bonds to be redeemed, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the "Treasury Rate" plus 50 basis points. The Trustee shall have the right to retain, at the expense of Energy Northwest, an independent accounting firm or financial advisor (which accounting firm or financial advisor shall be subject to Energy Northwest's approval) to determine the Redemption Price and perform all actions and make all calculations required to determine the Redemption Price. The Trustee and Energy Northwest may conclusively rely on such accounting firm's or financial advisor's calculations in connection with, and determination of, the Redemption Price, and shall bear no liability for such reliance.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2009-B (Taxable) Bond, the rate per annum equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue, assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price.

"Comparable Treasury Issue" means the U.S. Treasury security or securities selected by a Reference Dealer which has an actual or interpolated maturity comparable to the remaining weighted average life of the Series 2009-B (Taxable) Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining weighted average life of such Series 2009-B (Taxable) Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date for a particular Series 2009-B (Taxable) Bond, (i) the average of the Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or (ii) if the Trustee, or the independent accounting firm or financial advisor retained as described above, is unable to obtain four such Reference Treasury Dealer Quotations, the average of all such quotations.

"Reference Dealer" means (i) both Citigroup Global Markets Inc. and Goldman, Sachs & Co. or their respective successors; provided, however, that if either of them ceases to be a primary U.S. Government securities dealer in the City of New York (a "Primary Treasury Dealer"), Energy Northwest (with the approval of Bonneville) shall substitute therefor another Primary Treasury Dealer, and (ii) two other Primary Treasury Dealers selected by Energy Northwest (with the approval of Bonneville).

"Reference Treasury Dealer Quotations" means, with respect to each Reference Dealer and any redemption date for a particular Series 2009-B (Taxable) Bond, the average, as determined by the Trustee, or the independent accounting firm or financial advisor retained as described above, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to Energy Northwest, the Trustee and Bonneville by such Reference Dealer at 3:30 p.m. (New York City time) on the tenth day preceding such redemption date (or, if such day is not a business day, the next preceding business day).

Series 2009-C Bonds. The Columbia 2009-C Bonds are subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2019, 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.

Mandatory Redemption

The Columbia 2009-B Bonds maturing on July 1, 2024 (which shall be deemed to be Term Bonds), shall be redeemed prior to maturity randomly (or paid at maturity), not later than July 1 in the years 2023 and 2024 (to the extent such Columbia 2009-B Bonds have not been previously redeemed or purchased) and in the principal amounts set forth below, without premium, together with the interest accrued to the date fixed for redemption.

Year (July 1)	Amount
2023	$ 4,730,000
2024*	5,050,000

* Final maturity.

Partial Redemption

If less than all of the 2009 Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities to be redeemed. If less than all of the 2009 Bonds of a Series of any such maturity are to be redeemed, the 2009 Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot or in accordance with their respective standard procedures. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any 2009 Bonds of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such 2009 Bonds for redemption, the Trustee will treat each such 2009 Bonds as representing that number of such 2009 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such 2009 Bonds to be redeemed in part by $5,000.

Notice of Redemption

Notice of redemption of any 2009 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 2009 Bonds which are to be redeemed at their last addresses shown on the registration books for the 2009 Bonds. Such notice shall be deemed conclusively to be received by the Registered Owners of the 2009 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 2009 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the 2009 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 money sufficient for the redemption of the 2009 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such 2009 Bonds on the redemption date and the 2009 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 system is in effect with respect to the 2009 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the 2009 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 SYSTEM") will determine the particular ownership interests of 2009 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 2009 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of 2009 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 2009 Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any 2009 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 2009 Bond and such 2009 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 2009 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 2009 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 money to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to such 2009 Bonds. Defeasance obligations are defined in RCW 39.53 and include direct obligations of the United States and certain obligations of United States agencies and instrumentalities and others as defined under "Government Obligations" in Appendix H-1. See Appendix H-1, "SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Defeasance (Article XI)" for a discussion of defeasance of the 2009 Bonds.

As a condition to defeasing any Series 2009-B (Taxable) Bonds, Energy Northwest must deliver to the Trustee for the Series 2009-B (Taxable) Bonds either a ruling from the Internal Revenue Service (the "IRS") or an opinion of counsel to the effect that the Beneficial Owners of the Series 2009-B (Taxable) Bonds will not recognize income, gain or loss for federal income tax purposes as a result of Energy Northwest's defeasance of such Series 2009-B (Taxable) Bonds and will be subject to federal income tax on the same amount and in the same manner and at the same time as would have been the case if such defeasance had not occurred.

PURPOSE OF ISSUANCE

REFUNDING PROGRAM

In 2000, Bonneville presented to Energy Northwest a proposal for a "Debt Optimization Program." The Debt Optimization Program involved extending the final maturities of outstanding Columbia Net Billed Bonds coming due prior to 2013 through a series of refunding bond issues. Implementing the Debt Optimization Program was intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's United States Treasury debt and reduce Bonneville's overall fixed costs. 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 and minimize costs to rate payers; and (3) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. See "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - Debt Optimization Program" in Appendix A. In 2000, Energy Northwest, in response to the Bonneville proposal, adopted a Refunding Plan, which essentially adopted the Debt Optimization Program as proposed by Bonneville. In 2001, at Bonneville's request to increase the scope of the Debt Optimization Program, Energy Northwest revised such 2000 Refunding Plan to increase the average life of outstanding Projects 1 and 3 Net Billed Bonds by extending the maturity of such Bonds for any future refinancing of such bonds. A portion of the Series 2009-A Bonds and a portion of the Series 2009-B (Taxable) Bonds are being issued for such purpose.

An additional objective of the Refunding Plan is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville. None of the 2009 Bonds are being issued to advance refund outstanding, noncallable Net Billed Bonds.

In addition, when deemed appropriate by Energy Northwest and Bonneville, Energy Northwest issues bonds to refund outstanding bonds when prevailing market conditions cause such refunding transactions to produce significant expected debt service savings. A portion of the Project 3 2009-A Bonds and a portion of the Project 3 2009-B (Taxable) Bonds are being issued for this purpose.

REFUNDING BONDS

The Project 1 2009-A Bonds are being issued for the purpose of refunding (i) $5,895,000 aggregate principal amount of the Project 1 Prior Lien Bonds and (ii) $45,995,000 aggregate principal amount of the Project 1 Electric Revenue Bonds.

The Columbia 2009-A Bonds are being issued for the purpose of refunding (i) $7,905,000 aggregate principal amount (including compound interest) of the Columbia Prior Lien Bonds and (ii) $117,400,000 aggregate principal amount of the Columbia Electric Revenue Bonds.

The Project 3 2009-A Bonds are being issued for the purpose of refunding (i) $15,745,000 aggregate principal amount (including compound interest) of the Project 3 Prior Lien Bonds and (ii) $112,020,000 aggregate principal amount of the Project 3 Electric Revenue Bonds.

The Project 1 2009-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 1 2009-A Bonds and Project 1 2009-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 2009-B (Taxable) Bonds are being issued for the purpose of paying certain costs relating to the issuance of the Columbia 2009-A Bonds and Columbia 2009-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 certain costs of the Columbia projects described under "NEW MONEY BONDS" herein.

The Project 3 2009-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 3 2009-A Bonds and Project 3 2009-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 2009-A Bonds and the Series 2009-B (Taxable) Bonds and other available amounts will be deposited in the respective debt service accounts for each Series of Refunded Bonds and may be, at the direction of Energy Northwest, used to purchase certain 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 and amounts in the debt service accounts, 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 following table and to pay all or a portion of the interest on all Prior Lien Bonds and the fixed rate Electric Revenue Bonds to be refunded to the date of their retirement.

The Bonds to be refunded with the proceeds of the 2009 Bonds are identified below.

Prior Lien Bonds to be Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Redemption/ Maturity Date	Redemption Price
1	1990B	$ 895,000	2009	7.25%	July 1, 2009	N/A
1	1993B	1,950,000	2009	7.00	July 1, 2009	N/A
1	1996C	2,110,000	2009	6.00	July 1, 2009	N/A
1	1998A	940,000	2009	5.75	July 1, 2009	N/A
Columbia	1994A	2,750,000(1)(2)	2009	CIB(1)	July 1, 2009	N/A
Columbia	1998A	5,155,000	2009	5.75	July 1, 2009	N/A
3	1989A	1,730,000(1)(2)	2009	CIB(1)	July 1, 2009	N/A
3	1989B	6,250,000(1)(2)	2009	CIB(1)	July 1, 2009	N/A
3	1990B	3,000,000(1)(2)	2009	CIB(1)	July 1, 2009	N/A
3	1993B	3,020,000	2009	7.00	July 1, 2009	N/A
3	1997A	1,745,000	2009	6.00	July 1, 2009	N/A

(1) Compound interest bonds.
(2) This amount reflects the aggregate of principal and interest payable at maturity on July 1, 2009.

Electric Revenue Bonds to be Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Redemption/ Maturity Date	Redemption Price
1	1993-1A	$ 7,130,000(1)	2009	variable	May 1, 2009	100%
1	2006-A	36,990,000	2009	5.00%	July 1, 2009	N/A
1	2008-D	1,875,000	2009	5.00	July 1, 2009	N/A
Columbia	2001-B	48,000,000	2018	5.50	July 1, 2009	100%
Columbia	2003-F	2,855,000	2009	5.00	July 1, 2009	N/A
Columbia	2004-A	64,670,000	2009	5.25	July 1, 2009	N/A
Columbia	2004-C	1,875,000	2009	5.25	July 1, 2009	N/A
3	1993-3A	1,240,000(1)	2009	variable	May 1, 2009	100%
3	2003-D	100,665,000(2)	2018	variable	April 16, 2009	100%
3	2006-A	8,090,000	2009	5.00	July 1, 2009	N/A
3	2008-D	2,025,000	2009	5.00	July 1, 2009	N/A

(1) Scheduled sinking fund redemption installment.
(2) Subseries 2003-D-3-1.

NEW MONEY BONDS

The Series 2009-C Bonds and a portion of the Columbia 2009-B (Taxable) Bonds are being issued to finance a portion of the costs planned to be incurred during fiscal years 2009 and 2010 for certain capital improvements at Columbia, for operating costs and to pay costs of issuance relating to such bonds. The planned capital improvements at Columbia include: various computer system and security upgrades; plant fire detection system upgrade; plant license extension; replacement of the main condenser; replacement of the reactor recirculation motor and pump; cooling tower fill replacement; replacement of numerous other pumps and motors; and replacement of various pieces of equipment.

SOURCES AND USES OF FUNDS

SOURCES OF FUNDS:

Project 1

Principal of Project 1 2009-A Bonds	$	48,905,000
Principal of Project 1 2009-B (Taxable) Bonds		515,000
Original Issue Premium Project 1 Bonds		2,982,658
Total	$	52,402,658

Columbia

Principal of Columbia 2009-A Bonds	$	116,425,000
Principal of Columbia 2009-B (Taxable) Bonds		18,515,000
Principal of Columbia 2009-C Bonds		69,170,000
Net Original Issue Premium Columbia Bonds		10,704,983
Total	$	214,814,983

Project 3

Principal of Project 3 2009-A Bonds	$	116,055,000
Principal of Project 3 2009-B (Taxable) Bonds		970,000
Original Issue Premium Project 3 Bonds		11,703,284
Total	$	128,728,284

USES OF FUNDS:

Project 1

Deposit with refunding trustee for refunded Project 1 Prior Lien Bonds	$	5,895,000
Deposit with refunding trustees for refunded Project 1 Electric Revenue Bonds		45,995,000
Costs of Issuance* and additional proceeds		512,658
Total	$	52,402,658

Columbia

Deposit with refunding trustee for refunded Columbia Prior Lien Bonds	$	7,905,000
Deposit with refunding trustee for refunded Columbia Electric Revenue Bonds		117,400,000
Capital Improvements and Operating Costs		87,449,532
Costs of Issuance* and additional proceeds		2,060,451
Total	$	214,814,983

Project 3

Deposit with refunding trustee for refunded Project 3 Prior Lien Bonds	$	15,745,000
Deposit with refunding trustees for refunded Project 3 Electric Revenue Bonds		112,020,000
Costs of Issuance* and additional proceeds		963,284
Total	$	128,728,284

* Includes Underwriters' Compensation.

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2009 Bonds are special revenue obligations of Energy Northwest issued under and 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 ($64,660,000 of which were outstanding as of March 1, 2009), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2009 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 2009 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 2009 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Project 1 Separate Subordinated Resolution. There were outstanding as of March 1, 2009, $1,799,130,000 principal amount of Project 1 Electric Revenue Bonds.

The Columbia 2009 Bonds are special revenue obligations of Energy Northwest issued under and 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 ($181,825,000 of which were outstanding as of March 1, 2009), to the lien and pledge of the Columbia Prior Lien Resolution. The Columbia 2009 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 2009 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 2009 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Columbia Separate Subordinated Resolution. There were outstanding as of March 1, 2009, $2,177,940,000 principal amount of Columbia Electric Revenue Bonds.

The Project 3 2009 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 ($395,460,000 of which were outstanding as of March 1, 2009), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2009 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 Electric Revenue 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 2009 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Project 3 Separate Subordinated Resolution. There were outstanding as of March 1, 2009, $1,415,565,000 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 that 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 Bonds, the Columbia 2009 Bonds and the Project 3 2009 Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2009 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2009 Bonds and the Project 3 2009 Bonds. The owners of the Columbia 2009 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2009 Bonds and the Project 3 2009 Bonds. The owners of the Project 3 2009 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2009 Bonds and the Columbia 2009 Bonds. No Bondholder has a claim on the assets of any Project.

The 2009 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE 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 2009 Bonds, see Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Events of Default and 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 of the respective 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 THE 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 THE PRIOR LIEN RESOLUTIONS - Certain Covenants."

If the maturity of Prior Lien Bonds or Electric Revenue Bonds, including the 2009 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.

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 THE 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. 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 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 2009 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 2009 Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the 2009 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 2009 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 Foster Pepper PLLC, as Bond Counsel, concurrently with the issuance of the 2009 Bonds, will be subject to limitations regarding such creditors' rights. See Appendix D-1 - "PROPOSED FORM OF OPINIONS OF BOND COUNSEL" and Appendix D-2 - "PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL," respectively.

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the 2009 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. 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 2009 Bonds, pursuant to Separate Subordinated Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

Each of the Electric Revenue Bond Resolutions permits the use of certain credit facilities 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE 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 capability of the Net Billed Project 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 OF FISCAL YEAR 2009 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2009 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.

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Direct Pay Agreements," Energy Northwest and Bonneville executed an agreement with respect to each Net Billed Project pursuant to which Bonneville agrees to monthly pay all costs for each Net Billed Project directly to Energy Northwest and each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

All payments required to be made by Bonneville under the Net Billing Agreements, the Assignment Agreements, the 1989 Letter Agreement and the Direct Pay Agreements 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 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 (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 behalf. When Bonneville does so it notifies the related Participants by letter that it has made such voluntary payments to Energy Northwest. See Appendix A - "THE 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 by any other means. For example, in the event that it were 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 CONTRACTS."

Direct Pay Agreements

Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project ("Direct Pay Agreements") pursuant to which, beginning May 2006, Bonneville pays at least monthly all costs for each Net Billed Project, including debt service on the Net Billed Bonds, directly to Energy Northwest. Each Participant pays directly to Bonneville all costs associated with its power sales and other contracts with Bonneville instead of making such payments to Energy Northwest. The Net Billing Agreements provide that Energy Northwest is to bill budgeted costs less amounts payable from sources other than the Net Billing Agreements to Participants. Direct payments received from Bonneville under the Direct Pay Agreements are considered a source other than the Net Billing Agreements and, therefore, the Net Billing Agreements were not amended. In the Direct Pay Agreements, Energy Northwest agrees to promptly bill each Participant its share of the costs of the respective Project under the Net Billing Agreements if Bonneville fails to make a payment when due under the Direct Pay Agreements. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest. If the Direct Pay Agreements were terminated, Bonneville and Energy Northwest would return to the payment procedures described under "Payment Procedures" above. See "SECURITY FOR THE NET BILLED BONDS – Pledge of Revenues and Priority," and Appendix A - "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - Order in Which Bonneville's Costs Are Met."

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 30 percent share of the terminated Trojan Nuclear Project owned by the City of Eugene, Oregon, acting by and through the 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 amounts appropriated 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 2008 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 other than to the United States Treasury, 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 made all payments to the United States Treasury in full and on time since 1984.

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 Nuclear 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 and payments under the Direct Pay Agreements, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury. The costs of the Net Billed Projects are currently covered through the Direct Pay Agreements rather than by net billing credits.

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 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 Federal System Operations and Maintenance Expense."

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."

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 1,157 megawatts and 27.5 megawatts, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, which has a maximum generating capacity of approximately 96 megawatts. Energy Northwest also owns and/or has financial responsibility for four nuclear electric generating projects that have been terminated: Projects 1, 3, 4 and 5. 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, 2008" 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, 2008.

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 March 1, 2009.

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF MARCH 1, 2009

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 64,660,000
Electric Revenue Refunding Bonds	1,799,130,000
TOTAL PROJECT 1	$ 1,863,790,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 181,825,000 (1)
Electric Revenue and Refunding Bonds	2,177,940,000
TOTAL COLUMBIA	$ 2,359,765,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 395,460,000 (1)
Electric Revenue Refunding Bonds	1,415,565,000
TOTAL PROJECT 3	$ 1,811,025,000
TOTAL NET BILLED REVENUE BONDS	$ 6,034,580,000
Packwood Revenue Bonds (2)	$ 1,300,000 (3)
Nine Canyon Wind Project Revenue Bonds (2)	$ 148,435,000

(1) Includes $6,224,350 accreted value of Compound Interest Bonds for Columbia and $230,598,730 accreted value of Compound Interest Bonds for Project 3, each as of July 1, 2008.

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

(3) This is the total amount of a line of credit with Bank of America, N.A.

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 24, consisting of 20 public utility districts and the cities of Richland, Seattle, Tacoma and Port Angeles, 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 24 utility 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 State 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 State 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
Sid W. Morrison, Chairman	Retired Executive	June 2009
Tom Casey, Vice Chairman	Public Utility District Commissioner	June 2010
David Remington, Secretary	Financial Consultant	June 2012
Kathleen Vaughn, Assistant Secretary	Public Utility District Commissioner	June 2010
Edward E. Coates	Retired Utility Executive	June 2010
K.C. Golden	Executive	June 2009
Bill Gordon	Public Utility District Commissioner	June 2010
Dan G. Gunkel	Public Utility District Commissioner	June 2010
Jack Janda	Public Utility District Commissioner	June 2010
Lawrence Kenney	Retired Organized Labor Executive	June 2010
Tim Sheldon	Washington State Senator	June 2012

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	38 years
W. Scott Oxenford	Vice President, Nuclear Generation/Chief Nuclear Officer	25 years
John W. Baker	Vice President, Energy/Business Services	37 years
Sudesh K. Gambhir	Vice President, Technical Services	30 years
Dale K. Atkinson	Vice President, Operational Support	31 years
Albert E. Mouncer	Vice President, Corporate Services/General Counsel/Chief Financial Officer	28 years

EMPLOYEES

Energy Northwest currently employs approximately 1,195 employees. Of these employees, 326 are members of the International Brotherhood of Electrical Workers (“IBEW”), 150 are members of the United Steel Workers (“USW”) and 8 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 USW union members constitute the Security Force bargaining group; and the HAMTC union members comprise part of the Standards Lab Instrument Technicians. All of the collective bargaining agreements will expire in the fall of 2012. A no-strike clause is included in each of the agreements.

INVESTMENT POLICY

Energy Northwest invests its funds 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.

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 and Prior Lien Resolutions. The 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 THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Investment of Funds (Section 508)" and Appendix H-2 - "SUMMARY OF CERTAIN PROVISIONS OF THE 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. 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 1,157 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. Bonneville has acquired the entire capability of Columbia 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 a maintenance, operating, fuel and capital budget for Columbia of $397 million for the 2009 fiscal year, which ends on June 30, 2009.

The cost of production, using industry standard methodology (such cost calculation methodology includes general, administration and capital costs, but excludes debt service, taxes, depreciation and decommissioning costs), of Columbia electricity is budgeted at $48.24 per megawatt-hour for the 2009 fiscal year. This cost is higher than the $27.85 per megawatt-hour for the 2008 fiscal year because the 2008 fiscal year did not include a refueling outage. The next scheduled outage will be in May 2009. Energy Northwest continues to place a high priority on cost-containment. Columbia faced a significant weather event during fiscal year 2008 due to several days of excessively high winds which caused damage to several plant buildings. No injuries occurred and the plant remained on line at 100 percent power. The repair efforts are almost complete. The plant ran continuously for 383 days until an outage on August 21, 2008. The shutdown was due to a fluid leak in the digital electro-hydraulic system. After repairs were completed, the plant reconnected to the Federal System grid on August 24, 2008. In coordination with Bonneville, the decision was made to take the plant offline on November 14, 2008 for a planned maintenance outage. Columbia's repair teams took advantage of the planned outage to make repairs to plant systems aimed at increasing the plant's future reliability. The plant came back online on November 20, 2008 and ran continuously until a subsequent outage occurred on February 8, 2009. The plant's safety systems automatically disconnected the plant from the grid due to a momentary pressure drop in the digital electro-hydraulic system. Columbia's repair teams took advantage of the unplanned outage to make optional repairs to other plant systems aimed at increasing the plant's future reliability. After repairs were completed, the plant reconnected to the Federal System grid on February 13, 2009.

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. Initiatives to reduce losses of generation, such as reducing outage length and reducing or eliminating the occurrences of forced outages, are continually being evaluated and implemented.

To increase the regional value of the plant's generating capability over time, engineers continue to work on a proposal to renew Columbia's 40-year operating license by 20 years, from 2023 to 2043. The NRC established a protocol to handle license renewal applications and has granted 47 such requests since 2000. The final Columbia License Renewal Application is anticipated to be submitted in December 2009.

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 74.2% and has generated 166,798,013.71 megawatt hours (net of station use) of electric power through December 2008. However, in the past eight calendar years ending December 31, 2008, the cumulative capacity factor has been 90.5%.

Successful implementation of employee performance enhancement initiatives at Columbia has produced significant positive results in plant performance. Fiscal year 2006 was the best generating fiscal year at Columbia since commencing commercial operation, eclipsing the previous record in 2004. In fiscal year 2006, Columbia produced 9,636 million kilowatt hours of electric power while attaining a plant capacity factor of 99.4% and a plant availability factor of 99.6%. Columbia had its second best fiscal year generation in 2008 with production of 9,594 million kilowatt hours of electric power with a plant capacity factor of 98.9%.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for fiscal years ended June 30, 2007 and 2008 and 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 2007	FY 2008
Operations, Maintenance and Overhead	$219,153	$185,167
Nuclear Fuel	25,318	35,873
Spent Fuel Disposal Fee	7,634	9,036
Generation Taxes	2,529	4,019
Decommissioning	5,885	6,163
Depreciation and Amortization	74,678	72,983
Investment Income	(8,070)	(4,426)
Interest Expense and Discount Amortization	122,518	121,464
Other Expense/(Revenue)	(12,673)	(1,285)
Total Costs	$436,972	$428,994
Net Generation (GWhs) (unaudited)	8,017	9,594[(2)]

(1) Amounts derived from audited Energy Northwest financial statements.
(2) The major reason for the increase in generation from fiscal year 2007 to fiscal year 2008 was that Columbia was in the off cycle year for its two-year refueling and maintenance outage.

The Columbia Series 2009-B (Taxable) Bonds will finance a portion of the operating costs for fiscal year 2009.

Capital Improvements

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. In fiscal year 2008, the amount spent on capital improvements was $35.7 million. Energy Northwest expects to spend $81.8 million on capital improvements in fiscal year 2009. The capital improvements at Columbia include upgrading the plant access road and various security upgrades; plant license extension; replacement of the main condenser (the fiscal year 2009 Columbia Generating Station long-range plan estimated that the cost of the main condenser project would be $95 million over three years); replacement of feedwater drive turbine; replacement of the reactor recirculation motors and pumps; replacement of numerous other pumps and motors; and replacement of various pieces of equipment. The Columbia Series 2009-C Bonds will finance a portion of these capital improvements.

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 assigns 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. For the Third Quarter of 2008, the reactor safety and radiation safety cornerstones had only Green findings and all performance indicators were also in the Green finding region. The Safeguards (Physical Protection) cornerstone information is not publicly available.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary at www.nrc.gov. The Safeguards (Physical Protection) cornerstone performance indicators and inspection findings are not integrated into the 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 Third Quarter 2008 Regulatory Oversight Process Summary lists 93 plants, including Columbia, in the Licensee Response Column, seven plants in the Regulatory Response Column and three plants and one plant, respectively, in each of the next two lower columns. There are no plants currently included in the Unacceptable Performance Column.

Institute of Nuclear Power Operations

The nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. The INPO 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 24 months since the initial date of commercial operation.

INPO completed a peer evaluation of Columbia in December 2008. A number of strengths and accomplishments were noted as well as areas for improvement. Based on the results of the plant evaluation, INPO defined Columbia's performance category as "overall performance is exemplary. Industry standards of excellence are met in many areas. No significant weaknesses noted." Energy Northwest had previously established an improvement program that will address areas for improvement identified in the evaluation.

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, among other things, to 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 May 2011 and is renewable for five-year terms thereafter. The Washington State Department of Natural Resources has entered into a lease with Energy Northwest for that portion of the bed of the Columbia River which encompasses the plant intake and discharge facilities. The Corps has issued a permit for construction and maintenance of the completed river facilities. Energy Northwest has an interim status permit for storage of mixed radioactive and hazardous wastes. 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 hexafluoride, enrichment of the uranium hexafluoride 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.

The 2003 through 2007 reload fuel design services have been provided pursuant to a contract with AREVA. The reload fuel supply for the 2009 through 2013 reloads will be provided pursuant to a contract with Global Nuclear Fuels – Americas, LLC.

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 the need for refueling outages every 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 uranium is sufficient for plant requirements through 2012.

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 ($9.036 million for the 12 months ended June 30, 2008). 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 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 2015. 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. See "NET BILLED PROJECTS LITIGATION AND CLAIMS – Energy Northwest v. United States of America."

Energy Northwest constructed the Independent Spent Fuel Storage Installation ("ISFSI") facility in 2002, to store spent fuel in commercially available dry storage casks on concrete pads at the plant site. The ISFSI facility can be expanded in increments to accommodate future spent fuel discharges when necessary.

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 $573.2 million (in 2007 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. Energy Northwest's estimate of Columbia's site restoration costs is approximately $80.6 million (in 2007 dollars).

The current decommissioning funding plan requires annual deposits to a fund through fiscal year 2024, the end of Columbia's current operating license with the NRC. 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 dismantling 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 November 30, 2008, totaled approximately $112 million. A separate fund has been established for site restoration. The balance of this fund as of November 30, 2008, totaled approximately $16 million. These amounts are held in external accounts 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 on Columbia. Claims relating to Columbia, Project 1 or Project 3 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 damages arising out of a nuclear incident. Federal law limits public liability for claims resulting from any nuclear incident to $12.52 billion under the Price-Anderson Act, as an amendment to the Atomic Energy Act of 1954 (as amended, "Price-Anderson").

In accordance with Price-Anderson, Energy Northwest has secured the maximum available insurance of $300 million in coverage for Columbia's public liability exposure. The remaining $12.22 billion of exposure is funded by the Secondary Financial Protection Program, available through assessments by the federal government in case of a nuclear accident. Under Price-Anderson, all nuclear reactor licensees can be assessed a maximum charge per reactor per incident. The maximum assessment for each nuclear operator per reactor per incident is $117.5 million, payable at no more than $17.5 million per reactor per incident per year (this assessment is payable under the Columbia Net Billing Agreements). The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident will be adjusted for inflation every five years. The next inflation adjustment should occur no later than October 29, 2013.

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 $2.75 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 net design electric rating of 27.5 megawatts. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles 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 2005 and an application requesting a new 50-year license was submitted to FERC in April 2008.

In fiscal year 2007, Packwood experienced its highest generation levels in the past five years, which were 6.3 percent above the 30 year average annual generation for the facility of 92,000 megawatt-hours. In fiscal year 2008, production at Packwood totaled 77,470 net megawatt hours, down significantly from the previous year due to the slow melting of record snow pack and the license requirement to maintain lake elevation to a certain level by the end of April. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs, including debt service on any Packwood bonds or notes. In November 2006, Packwood experienced damage due to land slides from the rain and flooding in Lewis County, Washington. Energy Northwest has requested grant money to make the necessary repairs and in December 2007, Packwood took out a line of credit with Bank of America, N.A. in the amount of not to exceed $1.3 million to provide interim financing for costs associated with repairing damage done to Packwood in recent landslide damage.

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. From November 2002 to September 2008, the power produced was sold directly to two of those participants, Benton County PUD and Franklin County PUD. Beginning in October 2008, Public Utility District No. 1 of Snohomish County is purchasing all the energy output of Packwood from the other participants for the period 2009 to 2011.

NINE CANYON WIND PROJECT

Energy Northwest owns and operates the Nine Canyon Wind Project, a wind energy project, which is capable of generating 95.9 megawatts of electricity. The project is located on leased land, near Kennewick, Washington. 49 wind turbines of the Nine Canyon Wind Project have a power generating capacity of 1,300 kilowatts each and there are an additional 14 wind turbines with 2,300 kilowatts of power generating capacity each. The turbines were manufactured by Siemens Power Generation, Inc. (previously BONUS Energy A/S). 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. 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 billed to the purchasers range from 5.0 cents per kilowatt hour to 6.6 cents per kilowatt hour during fiscal year 2008.

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 offered to sell assets in the form of uninstalled operating equipment and construction materials since 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. 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 $20 million in calendar year 2006 dollars. Bonneville has placed funds in an external interest-bearing account in order to have sufficient funds for the eventual final remediation.

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 offered to sell 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 combustion turbine site) was made in 1999 to such local public agencies for purposes of economic development. The Satsop combustion turbine site was sold in 2001 to Duke Energy Grays Harbor LLC for $10 million.

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. After 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 the resolution were released from all of their obligations thereunder.

ENERGY/BUSINESS SERVICES

More than a decade 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 tenth year of operation.

Energy Northwest is in negotiations to develop the Radar Ridge Wind Project (the "Radar Ridge Wind Project") with the Public Utility District Nos. 1 of Clallam and Grays Harbor Counties, the Public Utility District No. 3 of Mason County and the Public Utility District No. 2 of Pacific County. Energy Northwest has entered into a 40-year lease with the Department of Natural Resources for a site in Pacific County near Naselle, Washington that will support 27 to 54 multi-megawatt wind turbines and has submitted a generation interconnection request to Bonneville to interconnect the Radar Ridge Wind Project at the Naselle 115kV substation. An Interconnection Feasibility Study determined that 82 megawatts of capacity is available at this location. Public Utility District No. 2 of Pacific County has agreed to develop a substation, distribution and transmission facilities to serve the Radar Ridge Wind Project.

On July 27, 2005, the Board of Energy Northwest approved the formation of a project for the purpose of eventually building an Integrated Gasification Combined Cycle power plant known as the Pacific Mountain Energy Center (the "PMEC"), now known as Kalama Energy. Energy Northwest requested and received an 18-month extension on the site permitting process from the Energy Facility Site Evaluation Council. The extension will keep options available for public power. The site's property lease was renegotiated down to 16 acres to reduce costs. Options for a natural gas power plant on this site are being assessed.

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 or the Net Billing Agreements.

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:

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 and 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 was originally in the aggregate amount of $5,612,447, but due to corrections to the audit, the assessment has been reduced to $149,495. 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. Thus, the extent of Energy Northwest's liability with respect to this contingent claim will be no greater than $149,495.

Energy Northwest v. United States of America. This is an action filed by Energy Northwest against the United States of America (the "Government") in the U.S. Court of Federal Claims in January 2004 for breach of contract and breach of implied covenant of good faith and fair dealing. On June 13, 1983, Energy Northwest entered into a written contract with the United States for disposal of spent nuclear fuel ("SNF") and high-level radioactive waste. The Government, in its contract, agreed to accept and dispose of the SNF beginning not later than January 31, 1998. The Government failed to meet its obligation and the date of performance is unknown at this time. Energy Northwest seeks recovery of damages for, among other things, substantial costs resulting from the Government's breach of contract, including but not limited to (1) the costs to investigate, design, license, and construct alternative storage facilities and to purchase and load casks to store SNF at those facilities; and (2) the operations, maintenance, and security costs Energy Northwest will incur to store SNF at Columbia beyond the time that the Government would have removed all the SNF had it not breached the Standard Contract. On January 30, 2006, the U.S. Court of Federal Claims ruled that the Government breached its contract with Energy Northwest as of January 31, 1998, when it failed to begin accepting SNF from the nuclear utility industry on that date. Trial was conducted from February 2 to February 20, 2009, and will be followed by post trial briefing due in April 2009. The Court has taken the case under advisement and will make a decision at some point after the post trial briefing has been submitted. The extent of the damages award cannot be predicted at this time.

LEGAL MATTERS

The approving opinions of Foster Pepper PLLC, Bond Counsel to Energy Northwest, as to the legality of the 2009 Bonds will be in substantially the form appended hereto in Appendix D-1 - "PROPOSED FORM 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 2009-A Bonds and the Series 2009-C Bonds from the gross income of the owners 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 FORM 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 that 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

SERIES 2009-A BONDS AND SERIES 2009-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, interest on the Series 2009-A Bonds and the Series 2009-C 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"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Section 103 of the Internal Revenue Code of 1986 (the "1986 Code"). Special Tax Counsel is of the further opinion that interest on the Series 2009-A Bonds and the Series 2009-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. Special Tax Counsel expresses no opinion as to whether some or all interest on the Series 2009-A Bonds and the Series 2009-C Bonds 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 2009-A Bonds and the Series 2009-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."

To the extent the issue price of any maturity of the Series 2009-A Bonds or Series 2009-C Bonds is less than the amount to be paid at maturity of such Series 2009-A Bonds or Series 2009-C Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2009-A Bonds or Series 2009-C Bonds, respectively), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the Series 2009-A Bonds or Series 2009-C Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Series 2009-A Bonds or Series 2009-C Bonds is the first price at which a substantial amount of such maturity of the Series 2009-A Bonds or Series 2009-C Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the Series 2009-A Bonds or Series 2009-C Bonds accrues daily over the term to maturity of such Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such Series 2009-A Bonds or Series 2009-C Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2009-A Bonds or Series 2009-C Bonds. Beneficial Owners of the Series 2009-A Bonds or Series 2009-C Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2009-A Bonds or Series 2009-C Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2009-A Bonds or Series 2009-C Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2009-A Bonds or Series 2009-C Bonds is sold to the public.

Series 2009-A Bonds or Series 2009-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.

Title XIII of 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 2009-A Bonds and Series 2009-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 2009-A Bonds and Series 2009-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 2009-A Bonds and Series 2009-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 2009-A Bonds and Series 2009-C Bonds may adversely affect the value of, or the tax status of, interest on these Bonds. Accordingly, the opinion of Special Tax Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Special Tax Counsel is of the opinion that interest on the Series 2009-A Bonds and Series 2009-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, state or local 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 2009-A Bonds and the Series 2009-C Bonds for federal income tax purposes. It is not binding on the IRS or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of Energy Northwest or Bonneville, or about the effect of future changes in the 1986 Act, the 1954 Code, the 1986 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville have covenanted, however, to comply with applicable requirements of the 1986 Act, the 1954 Code and the 1986 Code.

Future legislative proposals, if enacted into law, clarification of the 1954 Code, the 1986 Act, or the 1986 Code or court decisions may cause interest on the Series 2009-A Bonds and the Series 2009-C Bonds to be subject, directly or indirectly, to federal income taxation, to be subject to or exempted from state income taxation, or otherwise affect the tax status of such interest to Beneficial Owners. The introduction or enactment of any such future legislative proposals or clarification of the 1954 Code, the 1986 Act, or the 1986 Code or court decisions may also affect the market price for, or marketability of, the Series 2009-A Bonds and the Series 2009-C Bonds. Prospective purchasers of these Bonds should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation as to which Special Tax Counsel expresses no opinion.

Special Tax Counsel's engagement with respect to the Series 2009-A Bonds and Series 2009-C Bonds ends with the issuance of the Series 2009-A Bonds and Series 2009-C Bonds, and, unless separately engaged, Special Tax Counsel is not obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2009-A Bonds or Series 2009-C Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than Energy Northwest, Bonneville and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit 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 disagrees may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2009-A Bonds or Series 2009-C Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2009-A Bonds or Series 2009-C Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

SERIES 2009-B (TAXABLE) BONDS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, interest on the Series 2009-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 tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2009-B (Taxable) Bonds.

CIRCULAR 230 DISCLAIMER

Investors are urged to obtain independent tax advice regarding the Series 2009-B (Taxable) Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2009-B (Taxable) Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2009-B (Taxable) Bonds.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") and Fitch, Inc. ("Fitch") have assigned the 2009 Bonds the ratings of Aaa, AA 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 2009 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 2009 Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2009 Bonds from Energy Northwest and to make a bona fide public offering of such 2009 Bonds at not in excess of the public offering prices set forth on the inside cover pages of this Official Statement. Aggregate underwriters' compensation under the bond purchase contract for the 2009 Bonds is $2,653,976. The Underwriters' obligations are subject to certain conditions precedent contained in the bond purchase contract and they will be obligated to purchase all of such 2009 Bonds of the applicable series if any such 2009 Bonds are purchased. The 2009 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2009 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 2009 Bonds.

J.P. Morgan Securities Inc., one of the underwriters of the Series 2009-A Bonds and the Series 2009-C Bonds, has entered into an agreement (the "Distribution Agreement") with UBS Financial Services Inc. for the retail distribution of certain municipal securities offerings, including the Series 2009-A Bonds and the Series 2009-C Bonds, at the original issue prices. Pursuant to the Distribution Agreement, if applicable for this transaction, J.P. Morgan Securities Inc. will share a portion of its underwriting compensation with respect to the Series 2009-A Bonds and the Series 2009-C Bonds with UBS Financial Services Inc.

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 2009 Bonds, for the benefit of the owners and beneficial owners of the 2009 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 2009 Bonds, if material. Energy Northwest Annual Information is to be provided not later than December 31 of each year, commencing December 31, 2009. The Bonneville Annual Information is to be provided not later than March 31 of each year, commencing March 31, 2010. The Annual Information will be filed with each Nationally Recognized Municipal Securities Information Repository (the "NRMSIRs") (or provided to a transmitting entity approved by the SEC) 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 for the State of Washington. 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. Prior to July 1, 2009, the information will be available to holders of 2009 Bonds only if the holders comply with the procedures and pay the charges established by such information vendors or obtain the information through securities brokers who do so. Effective July 1, 2009, all such information must be filed with the MSRB, rather than the current NRMSIRs. The MSRB has indicated that it intends to make the information available to the public without charge through an internet portal. 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. There have been several state initiatives involving energy issues, including a recent one requiring certain electric utilities to obtain a percentage of their electricity from renewable resources.

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 2009 Bonds, the basic agreements securing the 2009 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 2009 Bonds is to be construed as a contract with the holders of such Series of 2009 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/ Sid W. Morrison
Chairman, Executive Board

By: /s/ Richard A. Bresnahan
Authorized Officer

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest ("Energy Northwest" or, the "Issuer") by Bonneville for use in the Official Statement, dated April 2, 2009, furnished by the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2009-A, Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A, Project 3 Electric Revenue Refunding Bonds, Series 2009-A, Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable), Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable), Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable), and Columbia Generating Station Electric Revenue Bonds, Series 2009-C (collectively, the "Series 2009 Bonds"). (Project 1, Project 3 and the Columbia Generating Station are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as the "Net Billed Projects.") 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 2009 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, is true and correct and does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this Appendix A and in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

GENERAL

Bonneville was created by an act of Congress in 1937 to market electric power from the Bonneville Dam located on the Columbia River and to construct facilities necessary to transmit such power. Congress has since designated Bonneville to be the marketing agent for power from all of the Federally-owned hydroelectric projects in the Pacific Northwest. Bonneville, whose headquarters are located in Portland, Oregon, is one of four regional Federal power marketing agencies within the United States 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 31 Federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-Federally-owned and -operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by Energy Northwest and having a rated capacity of approximately 1,157 megawatts. In addition, firm energy from transfers, exchanges, and purchases comprise the remaining portion of Bonneville's electric power resources. Not taking into account estimated power lost through the transmission of electricity from generation sites to load sites ("line losses"), Bonneville estimates that the foregoing projects and contracts have an expected aggregate output in the current operating year (August 1, 2008 to July 31, 2009) of about 10,600 annual average megawatts under median water conditions and about 8,550 annual average megawatts under low water conditions.

Bonneville sells, purchases and exchanges firm power, seasonal surplus energy (which is also referred to as "secondary" or "non-firm" energy), peaking capacity and related power services. Bonneville also constructed and operates and maintains a high voltage transmission system comprising approximately three-fourths of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities and power marketers.

Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the entirety of the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the 300,000 square-mile service area is approximately 12 million people. Electric power sold by Bonneville accounts for more than one-third of the electric power consumed within the Region. Bonneville markets a large portion of this power to over 125 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service

Bonneville provides to DSIs has diminished substantially relative to levels from the 1940s through the 1990s. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," may result in payments by Bonneville to the exchanging utilities if the applicable power rates for Federal Columbia River Power System ("Federal System") power are lower than the utilities' respective average system cost of meeting their residential and small farm power loads. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"). See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," "—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations to Preference Customers," and "—Power Marketing in Fiscal Years 2007 through 2011—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

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 POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates." Bonneville may also issue and sell bonds to the United States Treasury and use the proceeds thereof to fund certain activities established under Federal law.

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

Bonneville's cash receipts from all sources, including from both transmission and power services 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 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 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 Reclamation 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 payment responsibility to the United States Treasury of $963 million (including $210.5 million in principal payments in advance of due dates under the Debt Optimization Program as described in this Appendix A) in full and on time for Bonneville's fiscal year (October 1 – September 30, hereinafter "Fiscal Year") ended September 30, 2008 ("Fiscal Year 2008"). Bonneville has made all payments to the United States Treasury in full and on time since 1984. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Program."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the Direct Pay Agreements, and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. For a description of the Net Billing Agreements, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS." For a description of the 1989 Letter Agreement, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—General." For a description of the Direct Pay Agreements, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Direct Pay Agreements" and see, in this Appendix A, "BONNEVILLE FINANCIAL OPERATIONS—Direct Pay Agreements." In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements, cash payments, if any, under the 1989 Letter Agreement, cash payments, if any, under the Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS."

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

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

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 are volatile. Prices peaked in the Fiscal Year 2000-2001 period at levels that were many multiples of historical levels but declined in Fiscal Year 2002. Prices rose in subsequent fiscal years, although in the current fiscal year, power prices have declined. 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.

Bonneville believes that its revenues and expenses are, and will be, subject to several key risks: (i) the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from discretionary sales of energy and the cost of necessary power purchases Bonneville may have to make to meet contracted loads; (ii) the level of Bonneville's load serving obligation; (iii) water conditions in the Columbia River basin, which determine the amount of hydroelectric 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 power from the Federal System; (v) continued availability of the capability of existing generating resources; and (vi) operating costs, generally.

Power Loads and Related Contracts and Power Rates through Fiscal Year 2011

Regional Power Sales and Related Agreements in Fiscal Years 2009 through 2011

Under the Northwest Power Act, Bonneville has a statutory obligation to meet electric power loads in the Region that are placed on Bonneville by electric power utilities, including both Preference Customers and Regional IOUs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." To address Bonneville's role in meeting Regional electric power loads for the period after September 30, 2006, in early 2002 Bonneville began a discussion with customers and other interested parties in the Region (the "Regional Dialogue"). The Regional Dialogue was divided into two phases, with the initial phase focusing on the five years beginning October 1, 2006 and the second phase focusing on Fiscal Years 2012 through 2028. The culmination of the initial phase was Bonneville's issuance in February 2005 of its Policy for Power Supply Role for Fiscal Years 2007-2011 – Administrator's Record of Decision ("Power Supply ROD"). The Power Supply ROD formed the basis for a number of decisions regarding Bonneville's Regional power sales and related arrangements, and power rates for Fiscal Years 2006 – 2011, including the three fiscal years beginning October 1, 2006 (the "2007-2009 Rate Period") and the two fiscal years beginning October 1, 2009 (the "2010-11 Rate Period").

For a description of post-Fiscal Year 2011 power sales and related arrangements, see "—Power Sales and Related Arrangements in the Period after Fiscal Year 2011 in the Period after Fiscal Year 2011," below.

Bonneville and all of its Preference Customers have power sales contracts that will be in effect through September 30, 2011. Bonneville expects that its Preference Customer loads, together with a small amount of Federal agency and Reclamation loads that Bonneville serves, will range between 7,475 and 7,625 annual average megawatts in Operating

Years 2009 through 2011. Bonneville currently provides three basic types of power to Preference Customers, primarily to meet the customers' own requirements in the Region: (i) Block power, which is power provided in pre-determined amounts at pre-determined times to meet the customers' requirements, (ii) Requirements service, which is power provided as necessary to meet a customer's loads, and (iii) Slice of the System, which is a proportionate amount of power if, as, and when generated by the Federal System (a portion of the Slice product is sold as requirements power, to the extent that Federal System generation meets the Slice customers' loads, and a portion of the Slice product is sold as surplus power, to the extent that generation exceeds the Slice customers' loads). Requirements service may be either "Full Requirements" service, meaning that Bonneville is responsible for meeting all of the customer's electric power loads, or "Partial Requirements service," meaning that Bonneville is responsible for meeting all of the customer's electric power loads to the extent not met by electric power that the customer has otherwise committed to meeting its loads.

With respect to service to the aluminum industry DSIs, Bonneville has no statutory obligation but is authorized to sell them power. Bonneville has executed five-year contracts under which Bonneville began providing limited, monetized power benefits estimated to be in the amount of approximately $55 million per year in aggregate, to three aluminum industry DSIs beginning in Fiscal Year 2007. One of the three companies is no longer operating, and its benefits have been reallocated to the remaining two aluminum industry DSIs. In addition, Bonneville has agreed to make available up to 17 average megawatts of power to its one non-aluminum industry DSI through Fiscal Year 2011. In December 2008, the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which is a federal appeals court with limited original jurisdiction over many matters relating to Bonneville, identified a number of legal deficiencies in the agreements. The court did not set aside the agreements. Instead, it remanded the agreements to Bonneville to address the deficiencies. In view of the court ruling, Bonneville entered into an interim amended agreement with the two aluminum industry DSIs with respect to the remainder of Fiscal Year 2009 and expects to address the court's ruling by making further contract amendments or taking other actions for Fiscal Years 2010 and 2011. Bonneville has also proposed to conform the arrangements with the other DSI to the court's ruling. See "BONNEVILLE LITIGATION—DSI Service ROD Litigation," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—DSI Loads."

With respect to the six Regional IOUs, Bonneville has no contractual obligation to sell electric power to meet any of their loads through Fiscal Year 2011, although Bonneville does have certain contracts to sell power to Regional IOUs, which sales are not tied to the Regional IOUs' loads in the Region. For a description of Bonneville's post-Fiscal Year 2011 arrangements with Regional IOUs, see "—Power Sales and Related Arrangements in the Period after Fiscal Year 2011."

In total, Bonneville's aggregate load obligations for Operating Years 2009 through 2011 include: (i) the previously discussed Preference Customer, Federal agency, and Reclamation loads that are forecast to increase from 7,475 to 7,625 annual average megawatts plus (ii) other Bonneville exports and intra-regional contract obligations that vary from about 1,050 annual average megawatts to about 1,075 annual average megawatts. Bonneville expects that in aggregate its total load obligations will be about 8,530 annual average megawatts in Operating Year 2009, rising to 8,700 annual average megawatts by Operating Year 2011.

Bonneville estimates that the Federal System will be able to produce about 8,310 increasing to 8,370 annual average megawatts in Operating Years 2009 through 2011 under certain assumptions of low river flows and after taking into account power purchases and estimates of energy losses from transmitting power from generation sources to loads. Bonneville's Federal System generation estimates for each year include various assumptions, including assumptions about refueling or other scheduled outages that are planned for the Columbia Generation Station. See "POWER SERVICES—Description of the Generation Resources of the Federal System."

Given the foregoing expected resources and loads, Bonneville now anticipates that it will have energy deficits in Operating Years 2009-2011 ranging from a deficit of 221 annual average megawatts in Operating Year 2009 to a deficit of approximately 330 annual average megawatts by Operating Year 2011. Despite having projected deficits on a firm power basis, Bonneville is investigating cost-effective methods to meet annual energy loads during this period. Federal System deficits, if any, through at least Operating Year 2011, would be expected to be met primarily through a combination of the following actions: (i) relying on the occurrence of seasonal surplus (secondary) energy, which is, primarily, hydroelectric generation produced from better-than-historically-low water conditions (referred to as "Critical Water," see "POWER SERVICES—Description of the Generation Resources of the Federal System—Federal Hydro Generation)"; (ii) making short-term market power purchases; (iii) acquiring electric power from independent power producer-owned projects; (iv) employing cost-effective conservation programs and load management programs that reduce Bonneville's load obligations; and (v) purchasing hydro-storage to improve the timing of hydro-power generation or entering into power exchange agreements with other entities that need electric power at differing times than the Federal System so that power is returned to Bonneville at times when Bonneville's electric power demands are high. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—

Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." In addition, Bonneville may enter into electric power-related financial agreements that do not involve physical delivery in order to address price risk in the purchase and sale of energy in an effort to assure that it has cost effective access to power to meet its commitments.

Bonneville believes that the Federal System energy and capacity load resource projections are conservative, although many factors affect Bonneville's load/resource balance and actual surpluses or deficits in any year may vary from projections: Bonneville's analysis assumes Federal System hydro-generation using water conditions based on one of the lowest water years on record; Federal non-hydro resources operating at expected generation levels; and Federal System contract obligations and purchases delivered at maximum contract levels. In addition, Bonneville's current analysis includes Federal System power purchases and resources for which Bonneville has contracts.

Bonneville's load obligations for the period after Fiscal Year 2011 will be established under the terms of recently executed, long-term contracts. Bonneville has agreed, subject to certain terms and conditions, to meet the load growth that Preference Customers elect to place on Bonneville in the period after Fiscal Year 2011. Under these new agreements, Bonneville's loads in the post-2011 period will become better defined, especially in November 2009, when Preference Customers must specify how much of their load growth they will require Bonneville to meet. Other issues apart from load commitments could affect Bonneville's need for additional electric power, including, but not limited to, changing needs to assure transmission system stability and service, changing usage patterns particularly with respect to peak loads, and assumptions about the continuous availability of existing generation facilities. Bonneville will further explore the means by which it will meet loads and other generation supply needs, including through long-term resource acquisitions or other transactions. See "—Power Sales and Related Arrangements in the Period after Fiscal Year 2011."

2007-2009 Power Rate Proposal and the 2008 Supplemental Power Rate Proposal

In August 2006, Bonneville submitted to FERC proposed power rates of general applicability for the three fiscal years beginning October 1, 2006 and ending on September 30, 2009 ("2007-2009 Power Rate Proposal"). Among other things, the 2007-2009 Power Rate Proposal proposed rates applicable to wholesale power service to Preference Customers for their requirements. Almost all of Bonneville's firm resources are used to provide power to meet Preference Customer requirements. Bonneville submitted the 2007-2009 Power Rate Proposal to FERC in the summer of 2007.

Subsequent to the filing of the 2007-2009 Power Rate Proposal with FERC, the Ninth Circuit Court issued opinions on the Residential Exchange Program and related power rates proposed for Fiscal Years 2002-2006 (the "2002 Final Power Rates"). See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation." The rulings invalidated certain "Residential Exchange Program Settlement Agreements," which Bonneville had intended would set Bonneville's Residential Exchange Program obligations to the Regional IOUs from Fiscal Year 2002 through Fiscal Year 2011. The court also remanded Bonneville's power rates to Bonneville for action consistent with the rulings. In February 2008, Bonneville initiated a rate proceeding (the "2008 Supplemental Power Rate Proposal") to supplement the 2007-2009 Power Rate Proposal in a manner consistent with the court's rulings. The 2008 Supplemental Power Rate Proposal proposes to amend and supplement the 2007-2009 Power Rate Proposal principally by (i) adjusting Preference Customer power rate levels downward for Fiscal Year 2009 (the third and final year of the 2007-2009 Rate Period) and (ii) re-determining Residential Exchange Program benefits that should have been paid during the Fiscal Year 2002-2008 period and that will be paid in Fiscal Year 2009. Bonneville submitted the 2008 Supplemental Power Rate Proposal to FERC for review in August 2008. FERC has granted the proposal interim approval of the 2007-2009 Power Rate Proposal as supplemented by the 2008 Supplemental Power Rate Proposal. Bonneville is awaiting a final ruling on the proposal from FERC.

Bonneville's power sales to Preference Customers under the Slice of the System power product or to meet their net requirements under Block service, Partial Requirements service or Full Requirements service, are made at Bonneville's lowest cost rate class, the Priority Firm Rate ("PF Rate"). PF Rates in general reflect the cost of resources and other services provided to serve the related Preference Customers' net requirements loads and, except with respect to the Slice rate, reflect the benefit of revenues from sales by Bonneville of seasonal surplus energy. In the case of Slice, the participating customers receive a percentage share of the seasonal surplus energy of the Federal System and hence the Slice rate does not reflect the revenues Bonneville receives from its marketing of seasonal surplus energy. The Slice rate also does not incorporate the costs of risks associated with power supply and power purchase costs, which are borne directly by Slice customers. While each of the foregoing services is provided under PF Rate schedules, the applicable rate level depends on Bonneville's rate design and specific costs to provide the related service. For the ten fiscal years beginning with Fiscal Year 2001, Bonneville offered Slice both as a stand-alone product and as part of an integrated Slice/Block service. Beginning in Fiscal Year 2011, Bonneville will provide Slice only as part of an integrated Slice/Block product.

The PF Rate is also the basis for two other important Bonneville rates: (i) the Residential Exchange Rate, which is used to determine Residential Exchange benefits, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," "—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations," and "—Power Marketing in Fiscal Years 2007 through 2011—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits," and (ii) the Industrial Firm Power Rate ("IP Rate"), under which Bonneville is to serve DSIs. PF Rates, including Slice rates, are also established to recover the net costs of the Residential Exchange Program and the costs of power benefits that Bonneville provides to DSIs. As a general proposition, if Bonneville provides Regional IOUs with Residential Exchange Program Benefits, or DSIs with power benefits, Preference Customers bear such costs in PF Rates, including Slice rates. The IP Rate is based upon the PF Rate in a manner in which the IP Rate also serves to recover costs of Residential Exchange Program benefits.

Under the 2007-2009 Power Rate Proposal, as modified by the 2008 Supplemental Power Rate Proposal, Bonneville's wholesale power rates for the 2007-2009 Rate Period would in effect provide average base rate levels under PF Rates for Full Requirements service to Preference Customers of about $26.90 per megawatt hour. In contrast to the proposed Fiscal Year 2009 rate levels for Full Requirements service to Preference Customers, rate levels that were in effect in Fiscal Year 2006 (the last year of the prior power rate period) for similar service were about $29 per megawatt hour.

The rate level estimate for Full Requirements service to Preference Customers in the 2010-2011 Rate Period reflects the rate level determination only and does not take into account certain corrective downward billing adjustments to Preference Customers in their favor to correct past rate effects from the overpayment of Residential Exchange benefits payments to Regional IOUs in Fiscal Years 2002 through 2007. These corrective adjustments to Preference Customer's power bills correspond directly to "Look-back Amount Offsets" in Residential Exchange benefits payments to Regional IOUs. Look-back Amount Offsets are reductions in the Residential Exchange benefit payments to Regional IOUs to recoup past overpayments of Residential Exchange benefits arising out of the re-determination of such benefits for the period Fiscal Years 2002 through 2007. Bonneville estimates that the aggregate amount of such overpayments to Regional IOUs (and the amount Preference Customers' rates were overcharged for the overpaid benefits) which had yet to be corrected as of the end of Fiscal Year 2008, was about $679.1 million. In the 2008 Supplemental Power Rate Proposal, Bonneville proposes a goal of using Look-back Amount Offsets to recoup the Residential Exchange overpayments in full from the Regional IOUs by the end of Fiscal Year 2015. Likewise, Bonneville proposes a goal of providing billing adjustments to Preference Customers in amounts equal to the Look-back Amount Offsets so that the Preference Customers are made whole by the end of Fiscal Year 2015 for the past over-collection of rates from them. Bonneville reserves the ability to adjust in future rate proposals the period over which it will correct for accrued overpayments of past Residential Exchange benefits. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations to Preference Customers," and "—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

Bonneville's proposed power rates and record of decision for the 2007-2009 Rate Period, as supplemented by the 2008 Supplemental Power Rate Proposal, also include a determination of the level of Residential Exchange benefits for Regional IOUs for Fiscal Year 2009. The rate proposal would effectively set the level of such benefits for Fiscal Year 2009 at about $266 million in aggregate, although actual payments would be reduced by $15.1 million for a one-time adjustment for one of the Regional IOUs and an additional $70.8 million for the Look-back Amount Offsets in such fiscal year. By contrast, under the original 2007-2009 Power Rate Proposal and prior to the 2008 Supplemental Power Rate Proposal, Bonneville had assumed that such benefits would be about $301 million in aggregate under the since-invalidated Residential Exchange Settlement Agreements. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 Through 2011," "—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits," and "—Power Rates for Fiscal Years 2007 through 2009."

Power Rate Proposal for the 2010-2011 Rate Period

In February 2009, Bonneville issued an initial power rate proposal for the 2010-2011 Rate Period ("2010-2011 Initial Power Rate Proposal"). After conducting formal rate hearings and related proceedings, Bonneville will prepare a final rate proposal (the "2010-2011 Final Power Rate Proposal") and associated record of decision for submittal to FERC in July 2009. To address various risks, Bonneville proposes to continue the use of (i) "base rates" for Regional power sales that are set at levels Bonneville believes to be sufficient to yield a reasonably high probability of sufficient modified net revenues (described below in "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2008") and (ii) a rate level adjustment mechanism (the "Cost Recovery Adjustment Clause," or "CRAC") that allows rate levels to be reset at the beginning of the first year of the rate period and one time in the middle of the two year rate period, in each case according to costs and revenues. Among the main determinants of rate levels to be proposed under the 2010-2011 Final Power Rate Proposal are the level of Residential Exchange

Program benefits, Bonneville's expected Fiscal Year 2009 ending financial reserve levels, forecasts of energy prices that Bonneville can obtain for secondary energy sales, weather conditions, which determine the amount and timing of secondary energy from the Federal System hydroelectric generating resources, purchased power expense and forecast purchased power expense, forecasts of other expenses, the expected level of DSI power benefits in the 2010-2011 Rate Period, the availability and expected effectiveness of financial risk management tools, and assumptions of Federal System operations in view of the Endangered Species Act and other fish and wildlife requirements. The initial proposal for power rates to Preference Customers calls for an average increase in such rate levels of approximately 9.4 percent over current average PF rate levels for Full Requirements service, which Bonneville estimates are about $26.90 per megawatt hour. Rate levels and other features of the 2010-2011 Final Power Rate Proposal could differ, perhaps substantially, from the rate levels and other features of the 2010-2011 Initial Power Rate Proposal. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 Through 2011—Power Rates for Fiscal Years 2010 through 2011."

Power Sales and Related Arrangements in the Period after Fiscal Year 2011

All of Bonneville's power sales agreements under which Bonneville currently sells power or provides benefits to Regional Preference Customers and DSIs will expire at the end of Fiscal Year 2011. In anticipation of the impending expiration of these contracts, and in hopes of concurrently shaping Bonneville's long-term Residential Exchange Program obligations, Bonneville and its customers engaged in a second phase of the Regional Dialogue. This phase addressed, as the basis for new long-term power sales and related contracts, how Bonneville will implement a policy direction of limiting its power sales, at the lowest cost-based rates consistent with sound business principles, to roughly the output of existing Federal System generating resources in the period after Fiscal Year 2011. In the past, when Bonneville augmented its own resources with market or other generating resources, the costs of these typically more expensive purchases were melded in with the Federal System's very low, embedded cost power, creating one rate that masked both the real value of Federal System power and the costs of load growth.

Power Sales to Preference Customers

In December 2008, Bonneville and each of its Preference Customers entered into contracts for power service by Bonneville from Fiscal Year 2012 through Fiscal Year 2028 ("New Long-Term Preference Contracts"). There are two basic types of power service that Bonneville will provide under the New Long-Term Preference Contracts: (i) Slice/Block service, which is an integrated power product combining Slice and Block services similar to those Bonneville currently provides to certain Preference Customers, and (ii) Load Following service, under which the equivalent of Full Requirements or Partial Requirements service can be obtained from Bonneville. Under Slice/Block, Bonneville commits to provide a Slice of the System product together with fixed blocks of power at designated times. For a description of Slice of the System, see "—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Regional Power Sales and Related Agreements in Fiscal Years 2009 through 2011." Under Load Following service, Bonneville provides the actual power requirements of the related customer after taking into account generating resources, if any, that the customer has identified, consistent with certain contract conditions, as being used to meet its loads. A customer's net requirements loads, in general, are the customer's loads within its service territory that are served other than with the non-Federal System resources designated by the customer as being used to serve the customer's native loads.

Seventeen separate Preference Customers have elected to purchase Slice/Block as the type of service they will receive under their New Long-Term Preference Contracts. The remaining Preference Customers have elected to take Load Following Service. In aggregate, the Slice of the System sales under the new Long-Term Preference Contracts represent about 25 percent of Federal System generation. By contrast, Bonneville currently sells about 22.6 percent of the Federal System generation as a Slice of the System product. Preliminary revenue forecasts for Fiscal Year 2012 indicate that loads met under Load Following service will be about 4,160 average annual megawatts, loads met by the Block portion of Slice/Block service will be about 1,734 average annual megawatts. Bonneville expects that the Slice portion of Slice/Block service will be about 2,200 average annual megawatts. The forecasts reflect an attempt to predict actual loads that will be met under the specified type of service, which loads vary with weather, economic and other conditions, and in the case of Slice, the actual generation of the Federal System.

All of the New Long-Term Preference Contracts for Load Following service subject the customers to a payment commitment under which they are required to pay for power tendered by Bonneville to the extent of the customer's net requirements. If a customer's loads decline, however, the customer's purchase obligation from Bonneville is reduced commensurately. Conversely, if a customer's net requirements decline due to reductions in the customer's own loads, the resulting excess power may not be purchased by the customer and remarketed. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their loads, although in the case of Slice, the cap only relates to that portion of their Slice purchases that are to be made in respect of their net requirements.

A key element of the New Long-Term Preference Contracts is the establishment of the basic features of a long-term rate methodology ("Proposed Tiered Rates Methodology") for periodically determining the applicable power rates throughout the term of the new contracts. Bonneville expects to employ two-year rate periods during the term of the New Long-Term Preference Contracts.

The contract provisions, in concert with the Proposed Tiered Rates Methodology, will restrict the power that Preference Customers may purchase in aggregate at "Tier 1 PF Rates" in general to an amount equal to the generating output of the currently existing Federal System. (Tier 1 PF Rates, which will be Bonneville's lowest cost base rates, will be used for Load Following service and Slice/Block service. While Slice/Block and Load Following Service will each be provided under Tier 1 PF Rates, the specific rate levels applicable to each such service will differ, reflecting Bonneville's differing rate design and specific costs to provide the respective types of service.) The amount of power to be purchased at Tier 1 PF Rates may be expanded in certain limited circumstances. These include: (i) an amount of up to 300 average megawatts in augmentation purchases of electric power to address specific issues related to the transition to the new contracts, including intervening load growth until Fiscal Year 2012, (ii) up to 250 average megawatts, if necessary, for new Preference Customers (to address the possible formation of new Preference Customers, Bonneville has also agreed to limit the aggregate amount of power that such new Preference Customers purchase at Tier 1 PF Rates to 250 annual average megawatts through Fiscal Year 2028), and (iii) 70 average megawatts for a potential load at a site operated by the DOE. In addition, Bonneville's obligation to sell power at Tier 1 PF Rates will be reduced if and to the extent that related existing Federal System resources, including the Columbia Generating Station, decline in capability. Any incremental purchases by such customers from Bonneville above this base amount of power, as augmented or reduced, will be sold at a presumably higher rate reflecting the incremental cost to Bonneville of obtaining additional power.

Each Preference Customer's right to purchase power at Tier 1 PF Rates in general will be determined based on the proportion that its net requirements bears to all Preference Customers' net requirements placed on Bonneville as of the end of Fiscal Year 2010, although the exact proportions are likely to adjust slightly over time based on the addition of the loads of new Preference Customers. Power for "Tier 2 loads," meaning any net requirements load placed on Bonneville by a customer in excess of its right to purchase at Tier 1 PF Rates, will be sold at rates that recover the marginal cost to Bonneville of acquiring the electric power needed due to such Tier 2 loads.

Bonneville initiated a formal rate proceeding in April 2008 to develop the Tiered Rates Methodology, issued a final methodology in October 2008, and shortly thereafter submitted it to FERC seeking a declaratory order that the methodology does not compromise Bonneville's ability to recover its costs. The methodology establishes certain long-term rate making principles to be followed during the term of the New Long-Term Preference Contracts. The Tiered Rates Methodology seeks primarily to define the costs that will be allocated for recovery in Tier 1 PF Rates and Tier 2 rates. Under the Tiered Rates Methodology, Tier 2 rates recover the costs of meeting Tier 2 loads while Tier 1 PF Rates recover the costs of the Federal System generating facilities including the costs assigned to power rates for the Net Billed Projects (some Net Billed Project debt service costs are assigned to be recovered in transmission rates), Federal System fish and wildlife costs, electric power conservation programs, transitional power augmentation as discussed above, the Residential Exchange Program benefits, and the net costs of any commitment to provide DSIs with electric power benefits in the post-2011 period. The Tiered Rates Methodology also proposes to allocate to Tier 1 PF Rates the benefits of revenues from Bonneville's sales of secondary energy derived from Tier 1 Federal System resources. Bonneville believes a reliable rate methodology in this regard must be specified to effectuate the New Long-Term Preference Contracts. Accordingly, the contracts include provisions tying the associated power sales to the Tiered Rates Methodology. As yet unspecified aspects of the Tiered Rates Methodology have been challenged in litigation. See "BONNEVILLE LITIGATION—Bonneville's Long-Term Regional Dialogue, Final Policy and Record of Decision."

Bonneville currently assumes that aggregate Tier 1 loads will at least equal the existing Federal System capability. In view of slowing economic conditions, Bonneville believes that the amount of intervening load growth that would increase Tier 1 loads could be relatively small and that the amount of the Tier 1 augmentation described above will likely be significantly less than 300 average megawatts. It is possible that no Tier 1 augmentation will be needed for this purpose and that there could be a slight surplus of Tier 1 power available beyond the amount needed to meet the customers' net requirements in Fiscal Year 2012. While Bonneville expects that new Preference Customers will be formed and/or seek service from Bonneville, Bonneville is unable to predict whether, when or the extent to which they will seek such service.

Tier 2 loads will become more clearly defined on November 1, 2009, which is the date by which the Preference Customers are required to notify Bonneville of the extent to which they will rely on Bonneville to meet their Tier 2 loads. Bonneville has offered several approaches for Preference Customers to define the extent, if any, to which Bonneville will meet their Tier 2 loads. Bonneville has provided the customers the ability to rely entirely on Bonneville to meet all such loads throughout the term of the contracts. Bonneville has also allowed the customers to rely on Bonneville, with specified notice to Bonneville, to meet all or a portion of their Tier 2 loads for defined multi-year periods through the term of the agreements. Under this approach, a participating Preference Customer could require Bonneville to meet none, all or designated portions of the customer's Tier 2 loads. In addition, Bonneville will allow customers to make all or portions of their Tier 2 purchases from specified resources or resource pools obtained by Bonneville. This is expected to assist such customers in meeting renewable resource or other requirements or goals.

Bonneville has begun developing the means by which it will meet any incremental load obligations under Tier 1 and/or Tier 2, and DSI loads after Fiscal Year 2011. Bonneville expects to meet any such needs using a wide array of techniques, including short-term power purchases, electric power conservation, power exchanges, and long-term contracts to acquire generating resources. Under analyses in calendar year 2008, Bonneville forecasted that its Preference Customers would in aggregate have about 200 average annual megawatts of new load growth that could in theory be met through purchases from Bonneville at Tier 2 rates beginning in Fiscal Year 2012. Bonneville also estimated that about one-half of such Tier 2 loads would in fact be placed on Bonneville. Bonneville now believes, in view of current economic conditions, that actual load growth may be lower than previously forecasted and that the amount of Tier 2 loads placed on Bonneville in Fiscal Year 2012 may be less than originally forecasted.

There is substantial uncertainty in forecasting long-term loads and Bonneville's strategy for meeting any such loads placed on Bonneville will take such uncertainty into account. Bonneville initiated the development of a "2009 Resource Program" in early calendar year 2009. The program will systematically evaluate the means by which Bonneville will meet any marginal load commitments, including Tier 1 expansion, Tier 2 load growth, and DSI power sale commitments, consistent with statutory guidance governing the acquisition by Bonneville of new conservation and generating resources. Bonneville expects to finalize the 2009 Resource Program in October 2009. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region."

While almost all Residential Exchange Program benefits are paid to Regional IOUs, Preference Customers may also qualify for such benefits. The New Long-Term Preference Contracts include provisions under which Preference Customers may obtain Residential Exchange Program benefits after Fiscal Year 2011 but only for and to the extent their own generating resources in operation in Fiscal Year 2010 are used to reduce their net requirements (thereby reducing their access to power from Bonneville at Tier 1 Rates when compared to customers with no such resources). In effect, a Preference Customer will not be able to obtain Residential Exchange benefits in respect of new resources it adds after Fiscal Year 2010 to meet its loads. A Preference Customer has filed litigation challenging these and related terms. See "BONNEVILLE LITIGATION—Bonneville's Long-Term Regional Dialogue, Final Policy and Record of Decision."

Power Sales to DSIs

In January 2008, Bonneville sought public input on a draft long-term power sales contract with Alcoa, Inc. ("Alcoa"), the largest in terms of energy usage of Bonneville's three DSI customers. The draft agreement included terms under which Bonneville would have sold 240 annual average megawatts of power to Alcoa for ten years commencing in Fiscal Year 2012 declining to 180 annual average megawatts in Fiscal Years 2022 through 2028. The rate applicable to the sale would have been the IP Rate, which, in general, is a rate keyed off of the PF Rate with certain adjustments. Bonneville estimates that through Fiscal Year 2022, the draft Alcoa contract would have provided Alcoa with about $65-$70 million per year in lower-than-market price power benefits and increased Bonneville's net operating costs by a similar amount. Bonneville estimates that the draft agreement would have increased Preference Customer rates by slightly more than $.50 per megawatt hour during such period. Alcoa and Bonneville ultimately did not agree to terms on an agreement based on the draft. It is possible that Bonneville could begin developing a new long-term proposal for Alcoa in Fiscal Year 2009.

Bonneville currently has a contract with another aluminum industry DSI, Columbia Falls Aluminum Co. ("CFAC"), to provide it with monetized power benefits through Fiscal Year 2011. Bonneville currently provides CFAC with power benefits that are about one half of the benefits Alcoa currently receives. For the period after Fiscal Year 2011, Bonneville has indicated a willingness to provide CFAC with power benefits similar to the proposed Alcoa transaction but proportionately reduced to reflect CFAC's smaller loads. Bonneville expects to supply its third DSI, Port Townsend Paper Company, with 17 average annual megawatts following the expiration of its current agreement at the end of Fiscal Year 2011. Bonneville expects that such a power sale would be at the IP Rate, which is expected to be greater than the PF Rate.

Residential Exchange Program and Other Arrangements with Regional IOUs

With respect to the Residential Exchange Program, Bonneville originally proposed to enter into settlement agreements with Regional IOUs, which would have provided them with roughly $250 million in aggregate Residential Exchange Program benefit payments in Fiscal Year 2012, to be adjusted in successive years. In view of the Ninth Circuit Court's ruling invalidating the Residential Exchange Program Settlement Agreements, Bonneville has entered into long-term Residential Purchase and Sale Agreements ("Long-Term RPSA") from Fiscal Year 2012 through Fiscal Year 2028 with three of the Regional IOUs and has proposed to enter into Long-Term RPSAs with the three other Regional IOUs. Under these agreements and proposed agreements, Residential Exchange Program benefits will be determined by reference to the Residential Exchange Program provisions of the Northwest Power Act. To implement these statutory provisions, Bonneville must determine the applicable cost of resources ("average system cost") each participating utility bears to meet the loads of its residential and small farm customers. If such cost is greater than the Residential Exchange Rate, which is an adjusted version of Bonneville's PF Rate, Bonneville pays the participating utility the difference multiplied by the utility's qualifying residential and small farm loads. The utilities pass on the benefit of such payments by Bonneville by adjusting their residential and small farm customers' power bills.

To guide the determination of costs of service that are to be included in determining the applicable average system cost of a participating utility, Bonneville has in the past relied on an Average System Cost Methodology established in 1984 after FERC approval. In the fall of 2008, Bonneville issued a new Average System Cost Methodology that Bonneville will use in connection with determining the level of Residential Exchange Program benefits after Fiscal Year 2009 under the Long-Term RPSAs. The proposed new Average System Cost Methodology includes in the average system cost determination additional types of costs not formerly allowed under the old methodology. Among other items, the new methodology would allow the utilities to include federal taxes, a return on shareholder equity, and transmission costs. The new methodology also will allow Bonneville to rely on different records of account that are much less dependent on state utility commission treatment and which Bonneville believes will make average system cost determinations more streamlined than in the past.

There are a number of variables that make it difficult to predict the level of Residential Exchange benefits that Bonneville will provide in the period after Fiscal Year 2011. However, under the rates proposed in the 2007-2009 Power Rate Proposal, as modified by the 2008 Supplemental Power Rate Proposal, the aggregate amount of such benefits for Fiscal Year 2009 would be about $266 million although the amount actually paid to Regional IOUs is expected to be approximately $180 million after taking into account Look-back Amount Offsets and another billing adjustment. See "—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—2007-2009 Power Rate Proposal and the 2008 Supplemental Power Rate Proposal." Bonneville believes that the aggregate amount of such benefits (exclusive of expected reductions in payments from Look-back Amount Offsets) will probably be in the range of $150 million and $300 million per year in the 2010-2011 Rate Period, depending on the outcome of the final power rate proposal for such period.

Bonneville has submitted the new Average System Cost Methodology to FERC for review. Bonneville does not know when FERC will complete its review. A number of customers have voiced concerns about the new Average System Cost Methodology and Bonneville expects that the methodology, if approved by FERC, will also be challenged in litigation. A number of other elements relating to the Residential Exchange Program are or have been the subject of litigation.

Bonneville is also required by law to offer to sell power to meet the Regional IOUs' loads in the Region. In Fiscal Year 2000, Bonneville tendered such contracts to the Regional IOUs and none elected to execute them. As a consequence Bonneville has no such agreements in place through Fiscal Year 2011; however, Bonneville recently entered into such contracts with four of the six Regional IOUs for the period after Fiscal Year 2011. By law, Bonneville must meet any loads within the Region placed on it under the conditions specified by contract under a "New Resources Rate." This rate would in effect reflect the marginal cost to Bonneville of acquiring power to meet the loads plus certain other costs. Bonneville believes that it is unlikely, unless circumstances change, that Regional IOUs will place substantial loads if any on Bonneville under the post-2011 contracts because (i) there is no reason to expect that Bonneville's cost to meet such loads, as reflected in the New Resources Rate, would be significantly lower than the Regional IOUs' cost to meet such loads, (ii) the Regional IOUs are financially motivated to make investments in new generating facilities in order to obtain shareholder returns, (iii) most of the Regional IOUs have state-mandated renewable resource purchase obligations and would have to be assured that such obligations are addressed in any power purchases from Bonneville, and (iv) the Regional IOUs would not be able to control directly the terms and costs of the new resources Bonneville would obtain to meet the loads.

Bonneville's Financial Plan

In the summer of 2008 and coincident with the later stages of the development of the new long-term power sales and related agreements for the period after Fiscal Year 2011, Bonneville issued a "Financial Plan" that sets forth general guidance in several key areas of financial policy. Among the areas addressed in the Financial Plan are Bonneville's United States Treasury repayment probability, around which Bonneville develops its power and transmission rate proposals, and Bonneville's access to capital.

First, the Financial Plan continues Bonneville's practice of proposing power and transmission rates that each achieve a 95 percent probability of full and timely payment of Bonneville's related annual payment responsibilities to the United States Treasury over a two-year rate period (or an equivalent annual payment probability if Bonneville employs a rate period other than two years). Bonneville also indicated that it would propose any changes to the United States Treasury payment probability practice through a formal rate proceeding.

Second, the Financial Plan identifies Bonneville's access to capital as a key area of concern and proposes that Bonneville work toward developing a rolling 20-year horizon for assuring that its access to capital is sufficient to meet its infrastructure investment needs. Federal System investment needs encompass, primarily, the capital programs for the hydroelectric facilities of the Federally-owned dams, fish and wildlife facilities, and Bonneville's transmission system. These capital investments will enable Bonneville to meet the increasing demand for power, provide reliable and responsive transmission services, and help restore and enhance fish populations and wildlife habitat.

In February 2009, and after the Financial Plan was released, Congress enacted and the President signed into law a $3.25 billion increase in Bonneville's permanent borrowing authority from the United States Treasury. See "—Increase in Bonneville's Authority to Borrow from the United States Treasury." Nonetheless, in order to meet planned capital requirements over a 20-year period, Bonneville will develop a capital funding plan that takes into account forecasted capital investment needs, the new authority and its best uses, and other possible sources of capital such as the Debt Optimization Program and lease-purchase financing of transmission facilities.

In view of the new United States Treasury borrowing authority, Bonneville's preliminary belief is that its reliance on third party sources of funding will be reduced but not eliminated. To the extent that Bonneville incurs non-Federal payment obligations for associated debt, such obligations are likely to be on parity, in terms of Bonneville's statutory priority of payments, with Bonneville's payment obligations for Energy Northwest's Net Billed Project debt, including the Series 2009 Bonds.

Fiscal Year 2009 Expectations

Current analyses prepared outside of Bonneville but relied on by Bonneville indicate a water supply forecast for the Columbia River basin, as of March 19, 2009, of 82 percent of the 30-year average for Fiscal Year 2009, as measured in terms of millions of acre feet of water. Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and British Columbia. Current forecasts of runoff are preliminary indicators only and actual results could differ substantially from the projections.

As of January 2009, Bonneville forecast that cash reserves of $1.646 billion as of the end of Fiscal Year 2008 would drop to between $1.11 billion to $1.44 billion at the end of Fiscal Year 2009. Hydro conditions and market prices have deteriorated somewhat since the January forecast, indicating that expected cash reserves will likely be closer to the low end of the range forecast in January. Such expectations are subject to change.

Based on reserve levels in the Bonneville Fund, and forecasts of revenues and expenses as of the end of the first quarter of Fiscal Year 2009, Bonneville believes that there is a high probability that Bonneville will meet its Fiscal Year 2009 United States Treasury payment responsibilities on time and in full. Such belief is based on information and conditions early in Bonneville's current fiscal year, which are subject to change.

Increase in Bonneville's Authority to Borrow from the United States Treasury

On February 17, 2009, President Barack Obama signed into law a $3.25 billion increase in Bonneville's authority to borrow from the United States Treasury, bringing Bonneville's aggregate United States Treasury borrowing authority to $7.7 billion. This increase is to be used for the purpose of providing funds to assist in financing the construction, acquisition, and replacement of Bonneville's transmission system and to implement the purposes of the Northwest Power Act. As with Bonneville's other increments of United States Treasury borrowing authority, the new authority is available unless Congress were to enact a law to retract it and the new authority is revolving, meaning that as outstanding balances are paid, the authority to borrow is restored. The increase will help enable Bonneville to fund its near- and long-term capital investments. See "—Bonneville Financial Plan." Bonneville's preliminary view is that the new borrowing authority will reduce but not eliminate its reliance on lease-purchase and other third-party financing sources to fund its capital program. Bonneville has begun reviewing its capital sources and funding needs in light of the new legislation.

POWER SERVICES

Bonneville's Power Services is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. Power Services was responsible for about $2.3 billion in revenues, or 77 percent, of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2008.

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 Services—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 by Federal law or policy to power generation. Such projects were constructed and are operated by the Corps or Reclamation. 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 and other arrangements with power suppliers.

Bonneville defines "firm power" as electric power that is continuously available from the Federal System during adverse water conditions to meet 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.*, a 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 (measured in megawatts) and firm energy (measured in average megawatts). 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 2009 (August 1, 2008 through July 31, 2009), the total Federal System would be capable of producing about 8,550 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes about 650 annual average megawatts of firm energy from transfers and exchanges and about 115 annual average megawatts from renewable and non-utility generation projects. See the table "Operating Federal System Projects for Operating Year 2009."

Federal Hydro Generation

The share of hydropower from Federally-owned hydroelectric projects for Operating Year 2009 is estimated to be approximately 82 percent of Bonneville's total 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 2009."

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), that are based on certainty of occurrence.

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most months and in most water years. Bonneville estimates that in most months of an operating year and under most water and load conditions 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 as Bonneville acquires or augments to balance annual and seasonal firm energy needs with new resources or purchases, these resource additions will also contribute more peaking capacity. At this time, Bonneville's resource planning focuses primarily 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. As additional non-power requirements are placed on the Federal System hydroelectric operations and as peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity resources or purchases 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 month to month and depends on a number of factors, including weather conditions, stream-flows, 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 expected Federal System firm power generated under certain low water conditions, referred to as "Critical Water." 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 (or, secondary energy). The amount of seasonal surplus energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2009, the Federal System is estimated to generate seasonal surplus energy of 1,300 annual average megawatts, assuming average water conditions (median water flows). In wet water conditions (high water flows) the amount of annual energy surplus could be as much as 2,500 annual average megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small or not available at all.

The Corps and Reclamation 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 marketable power from these projects.

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table estimates the operation of the Federal System under the Pacific Northwest Coordination Agreement ("PNCA"). The PNCA defines the planning and operation of Bonneville, U.S. Pacific Northwest utilities and other parties with generating facilities within the Region's hydroelectric system. The hydro-regulation study incorporated measures, including but not limited to: (i) measures under the National Oceanographic and Atmospheric Administration Fisheries ("NOAA Fisheries") biological opinions relating to the Columbia River and tributaries and related court-ordered operations; (ii) the United States Fish and Wildlife Service ("Fish and Wildlife Service") biological opinions for certain Snake River and Columbia River dams; and (iii) operations described in the Council's Fish and Wildlife Program. These measures include increased flow augmentation for juvenile fish migration in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the Lower Snake and Columbia River dams to provide for non-turbine passage routes for juvenile fish migrants, and additional flows for Kootenai River white sturgeon in the spring. As new biological opinions (see "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act," and "—Columbia River System Biological Opinions" and "—Willamette River Project Biological Opinion") and similar non-power requirements are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in estimates of the availability of Federal hydropower under all water conditions.

Other Power Resources and Contract Purchases

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station, which has the largest capacity for energy production of the non-Federal resources. See Footnote 9 in the following table "Operating Federal System Projects for Operating Year 2009." In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. Bonneville projects that it will continue to have long-term contracts for transfers and exchanges that provide roughly 650 annual average megawatts.

Operating Federal System Projects for Operating Year 2009

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, stream-flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a 50 year record of river flows based on the period from 1929-1978 for planning purposes. During this period, low water conditions ("Low Water Flows") occurred in 1936-37, median water conditions ("Median Water Flows") occurred in 1957-58 and high water conditions ("High Water Flows") occurred in 1973-74. Bonneville estimates the energy generating capability of Federal System hydroelectric projects in an operating year 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 2009, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows, Median Water Flows and High Water Flows. The same forecasting procedures are also used for non-Federally-owned hydroelectric projects. Thermal projects, the output of which does not vary with river flow conditions, are estimated using current generating capacity, plant capacity factors, and maintenance schedules.

Operating Federal System Projects for Operating Year 2009(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 (Reclamation) Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	6,326	2,785	2,430	1,946
Hungry Horse	1952	4	361	155	104	83
Other Reclamation Projects(6)		16	225	162	154	129
1. Total Reclamation Projects		53	6,912	3,102	2,688	2,158
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,535	1,002	1,166	1,067
John Day	1968	16	2,484	1,199	1,092	788
The Dalles w/o Fishway(7)	1957	24	2,074	823	843	600
Bonneville	1938	20	1,047	597	571	403
McNary	1953	14	1,127	632	666	492
Lower Granite	1975	6	930	361	294	198
Lower Monumental	1969	6	923	382	321	199
Little Goose	1970	6	928	383	314	204
Ice Harbor	1961	6	693	211	243	178
Libby	1975	5	579	298	224	182
Dworshak	1974	3	445	281	203	148
Other Corps Projects(8)		20	198	306	285	242
2. Total Corps Projects		153	13,963	6,475	6,222	4,701
3. Total Reclamation and Corps Projects (line 1 + line 2)		**206**	**20,875**	**9,577**	**8,910**	**6,859**
Non-Federally-Owned Projects						
Columbia Generating Station(9)	1984	1	1,150	878	878	878
Other Non-Federal Hydro Projects(10)		7	31	61	49	46
Other Non-Federal Projects(11)		11	64	115	115	115
4. Total Non-Federally-Owned Projects		**19**	**1,245**	**1,054**	**1,042**	**1,039**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(12)		**n/a**	**473**	**651**	**651**	**651**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**225**	**22,593**	**11,282**	**10,603**	**8,549**

Source: Draft 2008 Pacific Northwest Loads and Resources Study, Bonneville, June 2008.

(1) Operating Year 2009 is August 1, 2008 through July 31, 2009. Discrepancies from the figures portrayed in the "2008 Pacific Northwest Loads and Resources Study" are due to rounding.

(2) January capacity is the maximum generation to be produced under Low Water Flows in megawatts of capacity. January is a benchmark month for the system peaking capability because of the potential for high peak loads during January due to winter weather. Bonneville further reduces estimates of its hydro peaking capacity to reflect that the hydro system has more machine capacity in its generating units than fuel (river flows) available to operate all units on a continuous basis.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows for energy in average megawatts. The hydro-regulation study incorporates measures prescribed by the NOAA Fisheries biological opinions relating to the Columbia River and tributaries and court-ordered operations; the Fish and Wildlife Service biological opinion for the Snake River and Columbia River dams; operations described in the Council's Fish and Wildlife Program; and other fish mitigation measures. If and to the extent the effects of new biological opinions or other measures to protect fish and wildlife are different than those assumed in the 2008 Pacific Northwest Loads and Resources Study, such changes will be reflected in future hydro-regulation studies. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "—Columbia River System Biological Opinions," and "—Willamette River Project Biological Opinion."

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

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

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

(7) The Dalles Dam complex also includes two units that generate energy in connection with a fishway at the dam. They produce approximately five megawatts of both peak capacity and energy. The output is not purchased by Bonneville and is not included in this table.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Bonneville Fishway (1981), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954) and Lost Creek (1975).

(9) Columbia Generating Station operates under a two-year maintenance and refueling schedule and a refueling outage is scheduled for Operating Year 2009. Bonneville assumes that the Columbia Generating Station will provide about 878 annual average megawatts in refueling years and 1,030 annual average megawatts in non-refueling years. The rated capacity of Columbia Generating Station is 1,157 megawatts, however, the 2008 Pacific Northwest Loads and Resources Study, upon which this table is based, assumes a capacity of 1,150 megawatts.

(10) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Mission Valley's Big Creek (1981), Lewis County PUD's Cowlitz Falls (1994), Boise Diversion (2004) and the Idaho Falls Power Bulb Turbine Projects (1982). Bonneville acquired the generation for the output from the Idaho Falls Power Bulb Turbine Projects (1982) through September 30, 2011. If Bonneville's contracts to purchase power from any of these projects are renewed, those projects will be included in future studies.

(11) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's 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 Hydro (1927) and Elwah Hydro (1910) projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), and Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, and a share of the City of Ashland's solar project.

(12) Bonneville Contract Purchases include contracts for power from both inside and outside the Region, including Canada.

Bonneville's Power Trading Floor Activities

Much of Bonneville's resource base is provided by hydroelectric facilities, the output of which is affected by weather conditions, stream-flows, operating constraints and other factors. In addition, other generation conditions and requirements generally may affect generation output. Thus, actual generation availability and output may vary hourly, daily, monthly or seasonally. In addition, power loads fluctuate based on consumer usage, demands to maintain transmission system stability and other factors. Thus, loads and availability of generation from Bonneville's own resources can vary substantially and, on an operational basis during a year, actual power from Bonneville's own generating resources may not match its loads. In the near-term (prior to and during a fiscal year), Bonneville routinely produces probabilistic and discrete studies estimating potential surplus or deficits for specific future time periods.

Based on these studies and specific marketing guidelines, Bonneville actively manages short-term surpluses and deficits through real-time, within-month, and forward sales and purchases and physical power options. Bonneville has put in place risk management procedures, standards and policies that it believes adequately mitigate risk from these activities. Nonetheless, Bonneville's exposure to operational variability means that Bonneville may in certain conditions have to incur substantial purchased power expense.

Customers and Other Power Contract Parties of Bonneville's Power Services

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 power sales revenues derived from such 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 SERVICES—Bonneville's Transmission System."

Bonneville has a large number of parties with whom it has commercial arrangements including, but not limited to, arrangements for the purchase, sale and/or exchange of power, transmission and related services. 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 that relate to other market participants that 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 for their load requirements in the Region. Such customers are eligible to purchase power at Bonneville's lowest cost rate, the PF Rate, for most of their loads, and 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, 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. Bonneville also sells relatively small amounts of power to several Federal agencies in the Region. While such Federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at the PF Rate.

Direct Service Industrial Customers

Bonneville may, but is not required to, sell power to a limited number of DSIs within the Region for the purchase of power for their direct consumption. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. For several years prior to 1995, Bonneville's annual DSI firm loads averaged approximately 2,800 annual average megawatts. Since then, most of the aluminum industry in the Pacific Northwest has ceased to operate. For Fiscal Years 2007-2011 Bonneville has entered into surplus power sales contract arrangements with three DSIs. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—DSI Loads," "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period After Fiscal Year 2011—Power Sales to DSIs," and, "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

Regional Investor-Owned Utilities

In Fiscal Year 2001, Bonneville entered into certain agreements, 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. In May of 2007, these agreements were set aside by the Ninth Circuit Court. As a consequence of the court's rulings, Bonneville is in the process of implementing supplemental power rates, new Residential Exchange Program contracts, and related policies that will shape the nature and amount of Residential Exchange Program benefits to Regional IOUs. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," "—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits," and "—Power Marketing in Fiscal Years 2007 through 2011"; "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data"; and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

As required by the Northwest Power Act, Bonneville has offered, and four of the six Regional IOUs have agreed to, contracts under which Bonneville could serve Regional IOUs with electric power for their net requirements in the period after Fiscal Year 2011. The Regional IOUs must pay Bonneville's New Resources Rate for any purchases under the agreements and that rate recovers the cost of any resources acquired by Bonneville to meet the loads. Bonneville does not expect the Regional IOUs to place substantial loads, if any, on Bonneville. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011—Residential Exchange Program and Other Arrangements with Regional IOUs."

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 seasonal surplus (secondary) energy that is 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.

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

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

Effect on Bonneville of Developments in California Power Markets in 1999-2001

California power markets experienced historically high power prices and volatility in the period 1999-2001. For much of that period, the California investor-owned utilities (the "Cal-IOUs"), were faced with having a cap on the rates that they could charge their customers while being required to purchase virtually all of their power requirements at prices that were multiples of the rates they could charge. The weakened financial positions of the Cal-IOUs, particularly Pacific Gas & Electric ("PG&E"), which filed for protection under Federal bankruptcy laws in 2001, and Southern California Edison ("SCE"), also affected the financial condition of two entities with central roles in 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. Another such entity is the nonprofit California Power Exchange ("Cal-PX"), which suspended operations in 2001, but was theretofore responsible for operating a power exchange through which the Cal-IOUs were obligated to purchase virtually all of their power requirements. The Cal-PX filed for bankruptcy protection in March 2001.

The Cal-ISO and the Cal-PX have outstanding payment obligations to Bonneville for sales it made to them during 2000 and 2001. Bonneville estimates that its total exposure for unpaid sales under these agreements is about $84 million. Bonneville has 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 in 1999-2001, FERC initiated three proceedings to address, under the FPA, 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 one 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 certain periods in 2000 and 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. 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 were filed in the Ninth Circuit Court. The Ninth Circuit Court has issued an opinion remanding the matter to FERC to further consider the denial of refunds. However, in light of the Ninth Circuit Court's prior decision in the California Refund Docket described below, Bonneville believes that the outcome of the remand should have no impact on Bonneville's liability for refunds for sales in the Pacific Northwest.

In a second 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 required 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 moved FERC to dismiss the matter against Bonneville. On January 22, 2004, FERC upheld the dismissal of the Show Cause Order issued on June 25, 2003. Certain parties filed for rehearing of the matter and FERC denied the rehearing request. The parties appealed the matter to Federal appellate court and FERC has moved to dismiss the appeal. The Federal appellate court has not yet rendered a decision on the motion to dismiss the appeal.

In a third proceeding (the "California Refund Docket"), FERC reviewed the extent to which (i) the prices of power sales through the Cal-PX and to the Cal-ISO were "unjust and unreasonable" in certain periods in 2000 and 2001 and (ii) various power sellers that participated in such sales would be required to provide refunds. Bonneville was a net seller through the Cal-PX and to the Cal-ISO during the period at issue and FERC concluded that Bonneville had refund liability for such sales. In September 2005, the Ninth Circuit Court reversed FERC, holding instead that FERC lacked authority to order Bonneville to provide refunds. The California parties filed a writ of certiorari at the United States Supreme Court appealing the order. The Court denied the writ of certiorari and the matter has been remanded to FERC under the Ninth Circuit Court's ruling.

In December 2005, the California Attorney General and certain California utilities filed administrative claims with Bonneville alleging that Bonneville had a contractual obligation to abide by FERC's refund determinations and demanding refunds. In March 2006, Bonneville rejected the administrative claims. The total amount of the administrative claims against Bonneville included $170 million in specified damages plus an unspecified amount of additional damages that would require future FERC determinations in order to determine the damages, if any. There is currently pending a motion to stay the proceedings pending the outcome of some unresolved matters at FERC and the Ninth Circuit in related proceedings that could impact the claims filed in this proceeding.

In March 2007, separate complaints seeking unspecified damages related to certain Bonneville power sales into the Cal-PX and Cal-ISO markets were filed in the United States Court of Federal Claims by PG&E, SCE, the California Electricity Oversight Board (Case No. 07-157-C), and San Diego Gas & Electric Co. (Case No. 07-167-C) (collectively, the "Utility Claimants"). As noted above, in March 2006, Bonneville had denied administrative claims filed by the Utility Claimants. The contract damages sought in the administrative claims by the Utility Claimants included approximately $50 million with respect to the same power sales that are the subject of these complaints plus unspecified additional damages which would require future FERC determinations regarding whether the relief sought is appropriate and the level of damages, if any. The Utility Claimants allege that Bonneville is contractually obligated to provide refunds of amounts received in excess of the mitigated market clearing prices for certain periods in 2000 and 2001, as established by FERC in separate refund proceedings. The Utility Claimants allege breach of contract and also seek declaratory relief that they are entitled to recover the unspecified damages. The Utility Claimants also seek pre-judgment and post-judgment interest and litigation costs. In October 2008, Bonneville filed answers to the complaints.

In March 2007 a similar complaint was filed against Bonneville in the United States Court of Federal Claims by the Attorney General of the State of California ("California AG") related to additional sales made by Bonneville to the California Energy Scheduling Resources ("CERS") during the same time period and to some of the same transactions for which PG&E and SCE seek recovery. As noted above, in March 2006, Bonneville denied an administrative claim by the California AG with respect to these sales. The amount sought by the California AG in the administrative claim was $120 million plus unspecified additional damages which would require future decisions by FERC regarding whether the relief sought is appropriate and the level of any damages, if any. Thus, Bonneville estimates that contract damages claimed by California parties in the litigation arising out of the California Refund Docket are $170 million in aggregate specified damages plus an additional amount of unspecified damages. In October 2008, Bonneville filed an answer to the complaint. There is currently pending a motion to stay the proceedings pending the outcome of some unresolved matters at FERC and the Ninth Circuit in related proceedings that could impact the claims filed in this proceeding.

For a description of litigation between SCE and Bonneville arising out of developments in West Coast energy markets in 1999-2000, see "BONNEVILLE LITIGATION—Southern California Edison v. Bonneville Power Administration."

In Fiscal Year 2005 Congress enacted the Energy Policy Act of 2005 ("EPA-2005"), which subjects Bonneville to FERC jurisdiction on a prospective basis for purposes of establishing refund liability. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Certain Statutes and Other Matters Affecting Bonneville's Power Services

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 believes it does not have a statutory obligation to meet all firm loads within the Region. Bonneville is not obligated by law to sell power to a DSI.

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 (i) the capability of the utility's firm peaking capacity and energy resources used in operating year 1979 to serve its own loads; and (ii) 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 the Regional IOUs have generating resources, which they may use to meet their firm loads in the Region. Each of such customers has to identify 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 existing power sales contracts under which Bonneville has a load following obligation, including under the New Long-Term Preference Contracts. The Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load on Bonneville, although Bonneville will serve such new loads at a rate that is expected to be higher than the rates Bonneville will charge to meet the customers' existing loads as of Fiscal Year 2010. Bonneville has executed requirements agreements with four Regional IOUs for the period after Fiscal Year 2011. It is possible that Bonneville may also enter into power sales contracts for the period after Fiscal Year 2011 with its three current DSI customers.

See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011."

Although Bonneville has contracts to sell firm power to extra-Regional customers, Bonneville is not required by law to offer contracts to meet such 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 under the provisions of the Northwest Power Act; (ii) the amount of power purchases, resource acquisitions and other arrangements that Bonneville will have to make to meet contracted 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 "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011."

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

Bonneville's Resource Strategies for the Post-2011 Period. Continued competition, deregulation in the electric power market and loss of hydropower flexibility due to Endangered Species Act ("ESA") constraints have had major implications for Bonneville's resource acquisition strategy. While Bonneville expects energy deficits of less than 460 annual average megawatts on a planning basis through Operating Year 2011, Bonneville's 2008 Pacific Northwest Loads and Resource Study indicates deficits of 330 annual average megawatts by Operating Year 2018. Projected deficits post-2011 will depend in part on the nature of Bonneville's power sales commitments for that period. Given uncertainties over the amount of loads that Bonneville will be required to meet, especially in the period after Fiscal Year 2011, any resource investment that involves irrevocable, high fixed costs over a period longer than Bonneville's contracted load obligation may have risks related to matching long-term resource commitments with long-term revenue from power sales contracts. To implement a policy whereby Bonneville will seek to share the responsibility of meeting incremental Regional power loads, Bonneville's New Long-Term Preference Contract uses 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 "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011." Bonneville initiated the development of a "2009 Resource Program" early in calendar year 2009. The program will systematically evaluate the means by which Bonneville will meet any marginal load commitments consistent with statutory guidance governing the acquisition by Bonneville of new conservation and generating resources. It will also evaluate other issues apart from Regional load commitments that could affect Bonneville's need for additional electric power, including, but not limited to, changing needs to assure transmission system stability and service, changing usage patterns particularly with respect to peak loads, and assumptions about the continuous availability of existing generation facilities. Bonneville expects to finalize the 2009 Resource Program near the end of Fiscal Year 2009.

Short-Term Power Purchases. As noted, Bonneville's current policy for the post-2011 period is to provide Regional Customers with the opportunity to meet their own incremental loads without facing increased costs for service to their existing loads as a result of such decision. Nonetheless, should Bonneville assume incremental load obligations above the existing generating resources of the Federal System, Bonneville must obtain additional electric power. Bonneville believes that, in general, new sources of power 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. Short-term (less than five year) purchases are the one type of resource that meets incremental load obligations without incurring 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 not previously purchased power. In wet years, purchase requirements can be significantly reduced as Bonneville would meet more of its loads with seasonal surplus (secondary) hydroelectric power.

In contrast to a reliance on long-term resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville would 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.

Renewable Energy. Bonneville presently purchases a total of approximately 66 average megawatts from various wind energy projects in Wyoming, Oregon and Washington and small amounts of power from solar photovoltaic projects. Bonneville also has contracted to purchase 49.9 megawatts from a yet-to-be developed geothermal project in northern California. The geothermal project was originally scheduled to become operational in

December 2005 but it is not clear yet whether the site is a viable geothermal resource and the project site is the subject of on-going environmental litigation. The commercial operation date has been extended to October 1, 2011.

Acquisition of renewable resource output from specific projects is a potential source of energy to meet forecasted deficits. In addition to any renewable resource acquisitions, Bonneville has launched several initiatives. (1) Bonneville has formed a technical cross agency team dedicated to designing cost-effective means to integrate large amounts of wind into the Federal System. One of the team's first tasks was the examination of the potential for third-party generation to meet within-hour capacity needs (to increase and decrease third party generation in response to variations in wind generation). Bonneville issued a subsequent Request for Information ("RFI") for capacity sources. The RFI received 17 responses. Bonneville is evaluating the feasibility of the different responses and may acquire several projects to determine how such resources could be used in Bonneville's systems. (2) Bonneville has initiated a waste heat recovery/industrial efficiency pilot acquisition program. Such energy acquisitions will be designed to meet the criteria of the Energy Independence and Security Act of 2007. (3) Bonneville is preparing a study of the feasibility of utility-scale solar in the Region designed to enable Bonneville and its customers to independently self-evaluate various solar technologies, locations and contract ownership structures. (4) Bonneville has issued a renewable resource information request designed to provide Bonneville and its customers with information on renewable generation available for purchase over the next several years. (5) Bonneville expects to issue a Request for Proposals in late Fiscal Year 2009 to meet expected resource needs following completion of the 2009 Resource Program. (6) Bonneville continues to provide direct programmatic funding for research and development activities including long-term solar and wind data monitoring, the annual net (above market) costs of any acquisition of renewable resource project output, and the continuation of a power rate discount program in which Bonneville provides limited rate credits to customers that pursue renewable resources.

Electric Power Conservation. Bonneville also has programs intended to encourage the development of electric power conservation measures in the Region. Electric power conservation can reduce the demand for Bonneville to meet electric power loads. During the 2007-2009 Rate Period, Bonneville has provided and is providing a $.50 per megawatt-hour rate discount to those of its customers that implement conservation measures. Bonneville expects to continue the $.50 per megawatt-hour rate discount in Fiscal Years 2010 and 2011. In addition, Bonneville has a target of acquiring 52 average megawatts of new conservation during Fiscal Year 2009. Bonneville achieved new conservation savings of 58 average megawatts in Fiscal Year 2007 and 76 average megawatts in Fiscal Year 2008. Future conservation acquisition programs are expected to lessen Bonneville's reliance on spot market or other electric power purchases in the post-2011 period.

Residential Exchange Program

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

Under the Residential Exchange Program, Bonneville is to "purchase power" offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology limiting the costs that may be included in an exchanging utility's average system cost to the production and transmission costs that an exchanging utility incurs for power. Bonneville is then to offer an identical amount of power for "sale" to the utility for the purpose of resale to the exchanging utility's residential users. In reality, no power has changed hands. Bonneville instead has made cash payments to exchanging utilities in an amount determined by multiplying an exchanging utility's eligible residential load times the difference between the exchanging utility's average system cost and Bonneville's applicable Residential Exchange Rate (which is an adjusted version of the PF Rate), if such rate is lower. The 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."

See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations to Preference Customers" and "—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

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 in a manner 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 NOAA Fisheries and the 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 Reclamation that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the Federal System projects' power purpose (as opposed to other project purposes such as irrigation, navigation and flood control). These measures mitigate the impact on fish and wildlife of the construction and operation of hydroelectric dams of the Federal System.

Bonneville also implements and funds measures recommended by the Council to implement the Council Program, which the Council periodically amends. The Council Program calls for a variety of mitigation measures from habitat protection to main-stem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and require 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 projects in support of 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, Reclamation and Bonneville; and (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation 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 Fiscal Year 2008, Direct Costs and Replacement Power Purchase Costs in aggregate were about $602 million and Foregone Power Revenues were about $274 million.

The Endangered Species Act. As noted above, Bonneville, the Corps and Reclamation 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 ESA listings and resulting biological opinions 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 Reclamation, 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 thirteen species of anadromous fish (salmon and steelhead), and two species of resident fish (bull trout and sturgeon) 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 Federal System hydroelectric dam operations with respect to the anadromous listed species, and the United States Fish and Wildlife Service has developed biological opinions with respect to the resident listed species. These biological opinions provide information that Bonneville, the Corps and Reclamation 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 Reclamation demonstrate that jeopardy to listed species is being avoided. The legal adequacy of many of the biological opinions and the implementation thereof have been or are the subject of litigation and judicial review.

Operation of the Federal System hydroelectric dams consistent with the ESA 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. 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 that 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 1,000 average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the NOAA Fisheries biological opinion in 1995. The consequences of this and similar ESA-related decrements in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

These ESA listings and related actions to protect listed species and their habitat have resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville's fish and wildlife mitigation 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. Bonneville estimates that the total of Direct Costs and Operational Impacts was about $852 million in Fiscal Year 2006, about $716 million in Fiscal Year 2007, and about $876 million in Fiscal Year 2008. Direct Costs in Fiscal Year 2008 were higher than in Fiscal Year 2007 ($313 million in Fiscal Year 2007 compared to $327 million in Fiscal Year 2008), Operational Costs increased by about $146 million, from $403 million in Fiscal Year 2007 to $549 million in Fiscal Year 2008. The occurrence of different stream-flows in Fiscal Year 2007 when compared to those in Fiscal Year 2008 meant that less hydro-generation was foregone due to fish operations and as a result there was a decrease of Foregone Power Revenues from about $282 million in Fiscal Year 2007 to $274 million in Fiscal Year 2008. However, the differing stream flows also led Bonneville to incur greater Replacement Power Purchases, increasing from $121 million in Fiscal Year 2007 to $275 million in Fiscal Year 2008. Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council's Fish and Wildlife Program, discussed below. In the future, Bonneville will also provide funding under the funding agreements entered into with certain tribes and the states of Idaho and Montana. See "—Columbia River System Biological Opinions."

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

Included among the 13 biological opinion alternatives around which Bonneville developed its final power rates for the five years ended September 30, 2006 were several alternatives 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 1,200 annual average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales.

A number of interests filed litigation in connection with the 2000 Biological Opinion. In May 2003, the United States District Court for the District of Oregon ruled that the 2000 Biological Opinion was inadequate. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. On November 30, 2004, NOAA Fisheries finalized a "2004 Biological Opinion" to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court.

The 2004 Biological Opinion called for multi-million dollar improvements in fish passage facilities at Federal System dams on the Snake and Columbia rivers over the next ten years. In addition, the 2004 Biological Opinion called for enhanced efforts to reduce predation on juvenile salmon, improvements in downstream transportation of migrating salmon, and changes in fish hatchery operations. Federal agencies, including Bonneville, the Corps and Reclamation, estimated a total spending commitment of over $6 billion over the planned ten-year life of the 2004 Biological Opinion. This amount was roughly equivalent to forecasted spending under the 2000 Biological Opinion. As with the 2000 Biological Opinion, the 2004 Biological Opinion did not recommend implementation of dam breaching. In the opinion of the General Counsel to Bonneville, legislation by Congress would be required in order for the breaching of the dams to be authorized.

A number of interests filed litigation challenging the 2004 Biological Opinion. In October 2005, the United States District Court for the District of Oregon invalidated the 2004 Biological Opinion on a number of grounds and remanded the 2004 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service, American Rivers v. Bonneville Power Administration, and Pace v. Bonneville Power Administration." NOAA Fisheries issued a final biological opinion (the "2008 Columbia River System Biological Opinion") on May 5, 2008 (discussed below).

In calendar year 2008, Bonneville, the Corps and Reclamation, and a number of regional interests including five tribes, an inter-tribal association and the states of Montana and Idaho, signed a number of separate agreements to assure long-term fish and wildlife funding with respect to the Federal System. The agreements, collectively known as the Columbia Basin Fish Accords, are designed to improve habitat and strengthen fish stocks in the Columbia River Basin over the next ten years. Most of the funding will be provided by Bonneville. Under the agreements, the tribes and states commit to accomplishing biological objectives with the funds, linked to meeting the federal agencies' statutory requirements.

The agreement among the State of Idaho, Bonneville, and the Corps and Reclamation and the agreement among the State of Montana, Bonneville, and the Corps and Reclamation are similar to the agreements with the tribes in that they are designed to improve habitat and strengthen fish stocks. With regard to the Idaho agreement, the measures are focused primarily in the Snake River Basin. With regard to the Montana agreement, the measures are focused primarily on listed resident fish (non ocean-going) in Montana.

Under the foregoing agreements with the tribal interests, and Montana and Idaho, Bonneville has committed to make available roughly $933 million over the ten-year period.

Bonneville estimates that roughly 60 percent of its proposed funding commitments in the agreements would be for new work required for implementation of the final 2008 Columbia River System Biological Opinion and otherwise agreed to in furtherance of Federal statutory fish and wildlife purposes such as the Northwest Power Act. The remaining amounts committed to in these agreements affirm the continuation of activities for fish and wildlife in furtherance of the ESA and Northwest Power Act that would otherwise face funding uncertainty after Fiscal Year 2009. While the foregoing agreements provide funding assurances to implement many actions under the 2008 Columbia River System Biological Opinion to protect listed species under the ESA, the proposed agreements also assure funding for other fish restoration efforts including efforts under the Northwest Power Act.

Additionally, all of the agreements promote a collaborative relationship between the non-Federal parties and the Federal agencies. Under the agreements, the participating tribes and states agree that the Federal government's requirements under the ESA, the Federal Water Pollution Control Act and the Northwest Power Act are satisfied as to the identified Federal System hydropower projects in the Snake River and Columbia River drainages for the next ten years. The parties to the agreements also agreed that they will work together to support the agreements in all appropriate venues. The agreements would also specifically resolve, for these parties, ESA litigation regarding Federal System hydropower projects in the Snake River and Columbia River drainages now pending before the United States District Court for the District of Oregon. Bonneville also believes that the agreements have helped fulfill the court's requirement that the parties increase collaboration in preparing the 2008 Columbia River System Biological Opinion.

The agreement also provides a higher level of assured long-term funding, which was a concern raised by the court in reviewing past biological opinions.

On May 5, 2008, NOAA Fisheries issued the final 2008 Columbia River System Biological Opinion. In comparison to the 2004 Biological Opinion, the 2008 Columbia River System Biological Opinion calls for significant improvements in downstream juvenile passage survival performance standards, spill and operations that are better timed to the needs of individual listed fish species, expanded habitat program, expanded predation-management program, and specific commitments and timetable for site-specific fish hatchery consultations and reforms. Included in the new biological opinion are proposed structural modifications to the hydro-system which are expected to cost about $500 million inclusive of associated research to support those modifications.

These modifications are expected to be funded by specific Federal appropriations, primarily to the Corps. Bonneville expects that it will be responsible for including in its power rates as a repayment to the United States Treasury about 80 percent of the costs of the modifications, which is the estimated portion of such costs assigned by law or administrative practice to be recovered in Bonneville's power rates. (Bonneville does not expect that the modifications will be financed with Bonneville's statutory borrowing authority with the United States Treasury.) As with other appropriated investments in the Federal System, Bonneville depreciates the portion of the costs to be recovered in power rates from the dates the related capital facilities are placed in service through their expected useful lives. These modifications will be implemented over many years; thus, their costs will gradually be added to Bonneville's rates and appropriated repayment responsibility as they are placed in service.

The 2008 Columbia River System Biological Opinion does not call for dam-breaching, nor does it call for drawing down of reservoirs or other operational changes which could interfere substantially with hydro-electric generation to meet instant demands. Nonetheless, the 2008 Columbia River System Biological Opinion will affect dam operations and will increase both capital costs and operating expenses to Bonneville when compared to the prior biological opinion.

It is difficult to predict the aggregate increased cost to Bonneville that will arise from the 2008 Columbia River System Biological Opinion. Many measures in the new biological opinion have been implemented, are currently being implemented, or would otherwise be implemented, including under the tribal and state agreements discussed immediately above. Certain measures involve long-term costs or expenses that are difficult to predict. Qualified by the foregoing and other uncertainties, Bonneville estimates that the 2008 Columbia River System Biological Opinion together with the tribal and state funding agreements will in aggregate increase the expense portion of Bonneville's cost of service by approximately $100 million per year over the ten-year term of the agreements, and increase power rates (all other things being equal) by about four percent, in each case when compared to Fiscal Year 2008 rate levels. This amount does not include Bonneville's capitalized repayment responsibility for the appropriated costs of the structural modifications described above. As noted above the capital costs will be included for recovery in Bonneville's rates as a Federal System appropriation repayment responsibility to the United States Treasury as and when the related facilities are placed in service and then will be depreciated over their expected useful lives.

A number of interests, including the State of Oregon, certain tribes, and certain environmental organizations, have filed litigation challenging the 2008 Columbia River System Biological Opinion in the United States District Court for the District of Oregon. Named defendants include NOAA Fisheries, the Corps and Reclamation. Additionally, some interests have filed litigation against Bonneville in the Ninth Circuit Court. In the former litigation in the Federal district court, the parties are seeking injunctive relief to alter hydroelectric dam operations. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service, American Rivers v. Bonneville Power Administration, and Pace v. Bonneville Power Administration."

Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible changes in dam operations, under the Endangered Species Act or other environmental laws, and whether the 2008 Columbia River System Biological Opinion will, given the challenges in litigation, be upheld by the courts.

Willamette River Project Biological Opinion. The Willamette River Project consists of 13 federal dams owned and operated by the Corps, located on various tributary rivers within the Willamette River Basin in western Oregon. Eight of these 13 dams have hydroelectric power turbines, generating approximately 184 annual average megawatts. The electric power from the eight hydroelectric dams is marketed by Bonneville as part of the Federal System.

Under the ESA, Bonneville, the Corps and Reclamation (the "Action Agencies") submitted a "Biological Assessment" to the Fish and Wildlife Service and National Marine Fisheries Service (collectively, the "Services") in April 2000. The Biological Assessment described the Willamette River Project, its operations, maintenance activities, and measures proposed to protect ESA-listed fish species that inhabit the Willamette River basin. In May 2007, the Action Agencies supplemented the original Biological Assessment with updated information on salient aspects of the original Biological Assessment. The Services issued their final biological opinions in July 2008, each having a 15-year timeframe.

The reasonable and prudent alternative issued by NOAA Fisheries includes measures for stream flow, fish hatchery and habitat improvements, and major structural changes at various dams, including water temperature control and fish passage devices. One item will be funded solely by Bonneville. The proposed structural changes to the dams will require appropriations by Congress to the Corps, with Bonneville being assigned the responsibility to recover a share of the costs in its power rates. (Bonneville's share of a project's costs, as with all Federally–owned hydroelectric projects of the Federal System, is based on the statutory or administrative assignation of relative benefits and burdens among all purposes for the related project. These project purposes may include power generation, flood control, navigation, recreation, municipal water supply and other purposes.) The schedule for the return over time to the United States Treasury would depend upon a number of factors including the extent to which the measures are expense items or capitalized items to be recovered over their useful lives. Given the fact that many of these proposed mitigation actions involve new and relatively untried technology, Bonneville is unable to predict the costs of these measures. Bonneville believes that the costs could substantially increase its cost of power from these related dams. However, because these cost are likely to be blended in with all of the other financial obligations and revenue streams that Bonneville manages, Bonneville does not expect there to be a significant impact upon overall power rates. See "BONNEVILLE LITIGATION—ESA Litigation—Willamette River Project."

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 authorizes Bonneville to exercise its Northwest Power Act authorities to implement fish and wildlife mitigation on behalf of all of a Federal System project's authorized purposes under Federal law; not just those relating to the delivery of generation and transmission services to customers, but also non-power purposes such as irrigation, navigation and flood control. At the end of the fiscal year, Bonneville is required to recoup (*i.e.*, take a credit for) the portion allocated to non-power purposes. Included in this credit are Direct Fish and Wildlife Program Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was about $76 million, $66 million and $100 million in Fiscal Years 2006, 2007 and 2008, respectively. Forecasts of these 4(h)(10)(C) credits are treated as revenues in Bonneville's ratemaking process. At the close of each fiscal year, they are applied against Bonneville's payments to the United States Treasury. The 4(h)(10)(C) credits are initially taken based on estimates and are subsequently modified to reflect actual data. An important cost that may be recouped under section 4(h)(10)(C) is that of Replacement Power Purchases necessitated by the loss of generation arising from certain changes to hydroelectric system operations for the benefit of fish and wildlife. These costs occur annually and are highest in dry years when, historically, the output of the hydro-system is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

Council's Fish and Wildlife Program. In 2000, the Council revised and adopted a new Columbia River Basin Fish and Wildlife Program (the "2000 Program"). The Council amended 57 sub-basin plans into the 2000 Program in 2003 with "mainstream amendments" meant primarily to address mitigation issues related to operation of the Federal System. In 2005, the Council amended the 2000 Program to help focus mitigation actions on overcoming environmental limitations to increased fish and wildlife populations. In October 2007, the Council began the formal rulemaking process to amend the program as required by the Northwest Power Act. The Council plans to adopt a new program in early 2009.

The 2000 Program emphasizes an ecosystem approach to rebuilding fish and wildlife in the Columbia River basin. The Council sets forth an "integrated program" that integrates mitigation recommendations from both the 2000 Program created under the Northwest Power Act and recovery actions needed for Bonneville to comply with the ESA. 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." For the 2007-2009 Rate Period, Bonneville originally forecasted an average expense accrual budget level of $143 million per year for the expense portion of the Integrated Program, and $36 million per year for the capital portion. With the successful conclusion of the Columbia Basin Fish Accords and the expected implementation of the final 2008 Columbia River System Biological Opinion and the Willamette River Project Biological Opinion, the Integrated Program expense budget is expected to grow to $200 million in Fiscal Year 2009 and average $233 million in the 2010-2011 Rate Period. The capital program investments are expected to average $60 million per year in the same period.

Bonneville cannot provide 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 Programs or amendments thereto, or litigation relating to the foregoing.

Power Marketing in Fiscal Years 2007 through 2011

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 with its Regional customers for the period after October 1, 2001. Under the Subscription Strategy, Bonneville entered into long-term Subscription Agreements through which it contracted to sell all of its then available firm power to Regional customers for various terms.

Preference Customer and Federal Agency Loads. Under the Subscription Strategy, Bonneville entered into long-term power sales contracts directly or indirectly to provide power to meet loads of about 127 Preference Customers, which contracts, in view of certain subsequent amendments, all run through September 30, 2011. Bonneville also agreed to Full Requirements power sales agreements with eight Federal agencies to meet their loads, which, in aggregate, are estimated to be about 140 annual average megawatts in Operating Year 2009, increasing to 144 annual average megawatts in Operating Year 2011.

Bonneville sells Preference Customers four basic power products: Block sales, Slice of the System, partial requirements and full requirements. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Regional Power Sales and Related Agreements in Fiscal Years 2009 through 2011."

Under the foregoing agreements, as amended, Bonneville estimates that it will be obligated to provide roughly 7,475 to 7,625 annual average megawatts to meet Preference Customer, Federal agency, and Reclamation load obligations in Operating Years 2009 to 2011. For Operating Year 2009, about 1,618 annual average megawatts is sold as Slice of the System, about 1,880 annual average megawatts is in the form of Block service or the Block portion of Slice/Block service and the remainder is in the form of full or partial requirements service. 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 Slice of the System component of 1,618 annual average megawatts reflects the firm power component of the Slice product. Slice of the System customers also receive what otherwise would be seasonal surplus energy in amounts that depend on precipitation in the Columbia River basin and actual generation from Federal System resources.

Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits. In Fiscal Year 2001, Bonneville and the six Regional IOUs participating in the Residential Exchange Program entered into six separate ten-year contracts ("Residential Exchange Settlement Agreements") that attempted to settle Bonneville's statutory Residential Exchange Program obligations with respect to such utilities during the period July 1, 2001 through September 30, 2011. Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2001. These amendments and the exercise by some Regional IOUs of contractual provisions were intended to increase the amount of cash payments that Bonneville would make with respect to the Residential Exchange Settlement Agreements and reduce certain physical power sales thereunder. As a result, the annual aggregate cash payments to Regional IOUs that Bonneville paid under the foregoing arrangements were between $304 million and $367 million in the four fiscal years beginning with Fiscal Year 2002. In Fiscal Year 2007, Bonneville paid about $168 million to the Regional IOUs until it suspended payments in light of the Ninth Circuit Court's May 2007 ruling that the Residential Exchange Settlement Agreements were invalid. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation." In the 2008 Supplemental Power Rate Proposal, Bonneville has proposed new PF Rate levels and re-determined Residential Exchange Program benefit levels for Fiscal Years 2002 through 2009.

As noted above, the Ninth Circuit Court issued opinions substantially affecting the Residential Exchange Program and related power rates for Fiscal Years 2002-2006 (the "2002 Final Power Rates") and the 2007-2009 Rate Period and the 2010-2011 Rate Period. The court found that Bonneville's reliance on the settling of its obligations under the Residential Exchange Program Settlement Agreements was not consistent with the provisions in the Northwest Power Act establishing the Residential Exchange Program. The court also directed Bonneville to set power rates consistent with the rulings. Bonneville has undertaken and is undertaking of the following actions to address the court's rulings.

First, after the May 2007 court ruling setting aside the settlement agreements, Bonneville ceased making further Residential Exchange Program benefits payments to Regional IOUs based on the Residential Exchange Program Settlement Agreements.

Second, through the 2008 Supplemental Power Rate Proposal Bonneville has proposed to determine four principal items: (i) the Residential Exchange Program benefits levels that should have been set for Fiscal Years 2002 through 2008, (ii) the level of benefits to be paid in Fiscal Year 2009, (iii) the Preference Customer power rates that should have been set for Fiscal Years 2002 through 2008 (assuming the re-determined Residential Exchange Program benefits in such years), and (iv) new power rate levels for Preference Customers in Fiscal Year 2009.

Third, to replace the invalidated Residential Exchange Program Settlement Agreements, Bonneville developed and entered into short-term Residential Exchange Program agreements that will effect the Residential Exchange Program provisions of the Northwest Power Act for Fiscal Years 2009 through 2011. Bonneville has also entered into the Long-Term Residential Purchase and Sales Agreements ("Long-Term RPSAs") with three of the Regional IOUs for Fiscal Years 2012 through 2028 and has proposed to enter into similar agreements with the other three Regional IOUs.

Fourth, for the re-determination of program benefits through Fiscal Year 2008, Bonneville relies on an average system cost methodology established by Bonneville in 1984. Bonneville has also prepared and submitted to FERC for review a new average system cost methodology to apply in the determination of Residential Exchange Program benefit levels in the 2009-2010 Rate Period and beyond.

Fifth, Bonneville determined the means by which it will correct the overpayment of Residential Exchange Program benefits and the corresponding effects on Preference Customer rates. The re-calculation of Residential Exchange Program benefits resulted in reduced Residential Exchange Program benefit levels, and, as a consequence, in lower effective Preference Customer rates than would have otherwise been the case. Bonneville decided that past overpayments of Residential Exchange Program benefits (for the period Fiscal Year 2002 through May 2007, when Bonneville suspended the payment of Residential Exchange Program benefits) would be recovered through offsetting reductions to future Residential Exchange Program benefits and passing the benefits thereof on to Preference Customers in the form of corresponding downward adjustments in their power bills. Bonneville estimates that as of the end of Fiscal Year 2008, the un-recouped aggregate overpayment of Residential Exchange Program benefits was about $679.1 million. Bonneville has established a goal of recouping the remaining balance of overpayments of Residential Exchange Program benefits by the end of Fiscal Year 2015. See ",CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—2007-2009 Power Rate Proposal and the 2008 Supplemental Power Rate Proposal."

Sixth, Bonneville made lump sum payments in Fiscal Year 2008 from certain amounts arising in the Bonneville Fund from the scheduled payments to Regional IOUs but which Bonneville had suspended after the court set aside the Residential Exchange Program Settlement Agreements. The lump sum payments were made (i) to Preference Customers to correct overcharges only for the period during which the payments were suspended (reflecting adjusted rate levels for Preference Customers as proposed in the 2008 Supplemental Power Rate Proposal), and (ii) to Regional IOUs in anticipation of finally-determined Residential Exchange benefits for Fiscal Year 2008.

See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011—Residential Exchange Program and Other Arrangements with Regional IOUs." See also "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

<u>Residential Exchange Program Obligations to Preference Customers</u>. By law, Preference Customers may qualify for Residential Exchange Program benefits payments. The 2007-2009 Power Rate Proposal as supplemented by the 2008 Supplemental Power Rate Proposal includes proposed Residential Exchange Program benefits payments to qualifying Preference Customers of about $1.1 million in Fiscal Year 2009. The possibility that other Preference Customers may become eligible for Residential Exchange Program benefits after Fiscal Year 2011 is addressed in the New Long-Term Preference Contracts. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Sales and Related Arrangements in the Period after Fiscal Year 2011—Power Sales to Preference Customers."

<u>DSI Loads</u>. With respect to service to the DSIs for Fiscal Years 2007 through 2011, Bonneville and two aluminum industry DSIs (Alcoa and CFAC) executed power sales contracts in which Bonneville agreed to provide the financial equivalent of 560 megawatts of power in aggregate to such DSIs at a rate approximately equivalent to Bonneville's lowest-cost power rate, the PF Rate. Bonneville has also entered into a relatively small five year physical power sale with a public agency for service to a small non-aluminum industry DSI at a rate approximately equivalent to Bonneville's lowest-cost PF Rate. Bonneville's commitment to provide the monetized and power benefits to DSIs in the foregoing contracts was challenged in litigation by non-DSI customers and others. In December 2008, the Ninth Circuit Court agreed in part with the petitioners, holding that certain features of the DSI contracts did not comply with applicable law. The court did not invalidate the contracts but remanded the contracts to Bonneville to address the legal infirmities. Bonneville has taken action and expects to take further action to conform its existing agreements with the DSIs to the court's ruling. See "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

Power Rates for Fiscal Years 2007 through 2009

In Fiscal Year 2006, Bonneville developed new power rates for the three fiscal years beginning with Fiscal Year 2007. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—2007-2009 Power Rate Proposal and the 2008 Supplemental Power Rate Proposal." FERC has granted interim approval of the 2007-2009 Power Rate Proposal as supplemented by the 2008 Supplemental Power Rate Proposal. FERC has not yet granted final approval of the proposal.

Continued market price volatility and several consecutive years of below-average runoff have changed Bonneville's view of the risk and uncertainty it faces, particularly with regard to expectations of revenue from discretionary sales arising from hydroelectric generation and with respect to power purchases if necessary to meet Bonneville's power sales commitments. Bonneville also faces uncertainty regarding operational costs for fish programs in the 2007-2009 Rate Period.

Proposal to Continue Ability to Vary Power Rate Levels. A central feature of risk mitigation in the 2007-2009 Power Rate Proposal, as was the case in the prior power rate period, is the reliance on a cost recovery adjustment clause ("CRAC"). Under the CRAC, applicable rate levels (primarily, requirements service to Preference Customers other than service under Slice), for each of the three fiscal years in the 2007-2009 Rate Period would be subject to adjustment on the basis of projected financial results for the then-current fiscal year and without the need to engage in a formal, time consuming, rate proceeding. As designed, near the end of a fiscal year Bonneville would produce a projection of that fiscal year's financial results. If the projections were to fall below a defined threshold, a rate level increase for the entire following fiscal year would take effect on October 1. The triggering conditions for the CRAC, including as modified for Fiscal Year 2009 in the 2008 Supplemental Power Rate Proposal, did not occur and the CRAC did not trigger for Fiscal Years 2007, 2008 or 2009. Bonneville believes that intra-rate period rate level adjustment mechanisms can help address cost recovery risks during a rate period and help maintain an acceptably high probability of making full and timely payment to the United States Treasury during the 2007-2009 Rate Period.

Flexible PF Rate Program. To address unexpected cash flow needs that may arise during the 2007-2009 Rate Period, the 2007-2009 Power Rate Proposal includes provisions, referred to as the "Flexible PF Rate Program," for Bonneville to temporarily increase rates for power sold to participating Preference Customers. There are no triggering conditions to Bonneville's billing and collection of increased rates from participating customers; however, Bonneville designed the Flexible PF Rate to trigger if Bonneville projects a need for cash liquidity during any month of the 2007-2009 Power Rate Period. This mechanism enables Bonneville to increase its cash flows for a brief period on short notice to meet unexpected needs and reduces the need for Bonneville to have cash reserves.

Thirty-three Preference Customers executed contract amendments to participate in the Flexible PF Rate Program, providing up to roughly $190 million in cash flow flexibility in each year of the 2007-2009 Rate Period. Under the terms of the program, if and when Bonneville elects to trigger the Flexible PF Rate Program provisions, Bonneville will decide which of the participating customers' power bills will be adjusted and by how much. Each participating customer has provided a standby letter of credit to secure payment of power bills that include a Flex PF Obligation Amount. Bonneville believes that the Flexible PF Rate Program provides a reliable source of short-term funds and was the basis for Bonneville to propose lower power rates in the 2007-2009 Rate Period than would have been the case without the program. Bonneville has not triggered the Flexible PF Rate and, based on current financial conditions and expectations, Bonneville believes that its is very unlikely that it will trigger the Flexible PF Rate in the current fiscal year, the last year of the Flexible PF Rate Program.

Proposed Dividend Distribution Clause. The 2007-2009 Power Rate Proposal contains provisions that would continue a feature of the 2002 Final Power Rates, referred to as a "Dividend Distribution Clause," in which Bonneville would adjust rate levels to rebate rates in certain circumstances of high modified net power revenues. Bonneville has not made any rate rebates nor will it make such rebates under the Dividend Distribution Clause in the 2007-2009 Rate Period.

Adjustment to the CRAC to Cover Certain Fish Costs. The CRAC contains provisions allowing Bonneville to increase the permitted recoveries under the CRAC in the limited circumstances where certain fish and wildlife costs assumed in the rate proceeding prove to be higher than expected. Under a fish cost adjustment (referred to as the "NFB Adjustment"), the maximum revenues recoverable under the CRAC would increase if and to the extent there were to be certain "financial impacts" to fish and wildlife costs arising from changes in ESA compliance. Events that would permit initiation of the NFB Adjustment are a court order, court-approved agreements, an agreement related to litigation, a new biological opinion, or other specified actions. The net financial impacts include increases in foregone power revenue, power purchases, direct program expense, operation and maintenance expense borne by the Corps or Reclamation, and capital investment. As noted, the CRAC did not trigger for Fiscal Years 2007, 2008 or 2009.

Adjustment to Power Rates During the Year to Cover Certain Fish Costs. The 2007-2009 Power Rate Proposal includes provisions that allow power rate levels to be adjusted during a fiscal year under limited circumstances to recover the "financial impacts" associated with the events that could trigger the NFB Adjustment. Under this rate adjustment (referred to as the "Emergency NFB Surcharge"), power rates could be adjusted in the same year as the triggering event to recover the identified "financial impact" only if Bonneville forecasts that its probability of meeting its scheduled payments to the United States Treasury in full in such fiscal year is lower than 80 percent and if the financial impact is greater than $10 million. This provision did not trigger for Fiscal Years 2007, 2008 or 2009.

Relationship of the 2007-2009 Power Rate Proposal to Slice of System Power Sales. The Slice of the System power sales that are effective through Fiscal Year 2011 are not subject to the proposed CRAC and the risk mitigation features inherent in the proposed base rates because Slice customers cover a proportionate share of risk of the Federal System by paying a proportionate share of the actual costs of the Federal System. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—Preference Customer and Federal Agency Loads." The major determinants of the rate level for Slice are set by contract. Accordingly, the 2007-2009 Power Rate Proposal calculates a Slice rate for the 2007-2009 Rate Period based on actual costs of the Federal System, as was the case under the previous power rates.

Surplus Power Rates. With regard to rates for surplus power, the 2007 Final Power Rates continue 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, stream-flows, market conditions and numerous other factors. Unless Bonneville were to otherwise agree by contract, rates for the sale of surplus power are not subject to the CRAC.

Power Rates for Fiscal Years 2010 through 2011

In February 2009, Bonneville published its initial power rate proposal for Fiscal Years 2010-2011 (the "2010-2011 Initial Power Rate Proposal"), which marks the formal commencement of the administrative process for the determination of final power rates for the 2010-2011 Rate Period. Bonneville expects to complete the 2010-2011 Final Power Rate Proposal and submit it, together with supporting documentation, to FERC by August 1, 2009.

PF Rates for Requirements Service and Slice Power Rates. As proposed, average PF Rates for Block Service, and Full and Partial Requirements service (and excluding Slice service) would be $29.42 per megawatt hour, which is about 9.4 percent higher than current average PF Rates of $26.90 per megawatt hour. Average PF Rates are determined by dividing all PF Rate revenues by all energy sales made at PF Rates (as measured in megawatt hours and excluding Slice revenues and sales). The average PF Rate reflects a composite load shape reflective of all purchases by customers at PF Rates. PF Rates do not include transmission, Look-back Amount Offsets, which correct prior overpayments of Residential Exchange benefits, conservation credits and certain other adjustments. .

With respect to Slice service and the Slice portion of Slice/Block service, the proposed rate increase would be about 9.5 percent. Unlike rates for Requirements and Block service, Slice rates do not incorporate the costs of risks associated with power supply, secondary sales and power purchase costs. These are borne directly by Slice customers. Slice is a combined power product that includes sales in respect of the participating customers' net requirements and sales of secondary energy. As with prior power rate proposals, Slice power rates would not be subject to the proposed CRAC, described below, because Slice rates recover actual costs. For a description of Slice of the System, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Regional Power Sales and Related Agreements in Fiscal Years 2009 through 2011."

Residential Exchange. With respect to the Residential Exchange, the initial proposal assumes an average of $254 million per year in benefits to the residential and small-farm consumers of Regional IOUs and about $10 million per year to potential exchanging Preference Customers during the 2010-2011 Rate Period. Bonneville assumes that two Preference Customers, including Public Utility District No. 1 of Snohomish County, Washington, Bonneville's largest Preference Customer in terms of power sales, will begin participating in the Residential Exchange beginning in Fiscal Year 2010 with respect to certain of their generating resources. The final determination of aggregate Residential Exchange benefits will depend on the final Residential Exchange Rate and a determination of the average system costs of utilities participating in the Residential Exchange program. Under the initial proposal, the Residential Exchange Rate would be about $49.44 per megawatt hour (including transmission). Bonneville expects to complete its determination of the respective average system costs of exchanging utilities in late spring 2009. The final rate proposal will reflect the outcome of this process.

As noted, the proposed rates do not reflect adjustments to Preference Customers' power bills and Residential Exchange benefits payments made in respect of Look-back Amount Offsets. Bonneville proposes to decrease actual payments to

Regional IOUs under the Residential Exchange program by about an aggregate $72 million per year in Look-back Amount Offsets during the 2010-2011 Rate Period. Bonneville also expects to credit Preference Customers' power bills in like amounts. Thus, under the initial proposal, Bonneville would make $183 million per year in payments to Regional IOUs for Residential Exchange benefits, which is roughly the same as the amount Bonneville expects to pay in Fiscal Year 2009. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," "—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations," and "—Power Marketing in Fiscal Years 2007 through 2011—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

DSIs. With respect to DSIs, the 2010-2011 Initial Power Rate Proposal assumes that Bonneville will provide the monetized equivalent of serving about 385 average megawatts of aluminum industry DSI loads sold at the IP Rate of $36.37 per megawatt hour, with a net cost of about $59 million per year. The expected net cost is roughly the same as that expected under the DSI contracts prior to the Ninth Circuit Court's ruling in December 2008 remanding the contracts to Bonneville. Bonneville also assumes in the 2010-2011 Initial Power Rate Proposal that it will continue to sell about 17 average megawatts to the non-aluminum industry DSI, Port Townsend Paper, although the sale is assumed to be made at the IP Rate. The amounts for DSIs are rate-setting assumptions only and do not represent decisions by Bonneville regarding the nature of DSI service in the 2010-2011 Rate Period or beyond. Bonneville has committed to consult separately from the rate proceeding with all interested parties about arrangements for DSI service during the 2010-2011 Rate Period. See "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

Important Revenue, Costs, and Risk Elements. One of the important factors in the 2010-2011 Final Power Rate Proposal will be Bonneville's forecast of net secondary energy sales revenues in Fiscal Year 2009. The initial proposal was developed based on prior forecasts of net secondary sales. Forecasts of net secondary energy sales can change substantially and quickly depending on weather and power market conditions. Recently updated forecasts now indicate that net secondary revenues will be significantly lower than Bonneville assumed in developing the initial proposal. In view of dry weather conditions and below average hydro conditions in the Columbia River system in the current Operating Year, and low prices in energy markets in western North America, Bonneville forecasts that the amount of revenue it will receive from sales of seasonal surplus (secondary) energy will be lower than the assumptions used in preparing the initial power rate proposal. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2009 Financial Expectations." The expected decline in such revenues will place upward pressure on the 2010-2011 Final Power Rate Proposal. In addition, certain costs are placing upward pressure on rates as well. These include increases in operation, maintenance and capital costs to assure reliability and safe operation of the Columbia Generating Station (the plant will also undergo an extended outage in Fiscal Year 2011 for condenser replacement); increases in capital and operating costs of the Federal System hydroelectric projects to maintain and improve reliability and output; and new biological opinion requirements and implementation of Columbia Basin Fish Accords.

Other important components that will shape the 2010-2011 Final Power Rate Proposal include the mix of financial risk management tools that Bonneville will employ to meets its policy of setting rates that have a 95 percent probability of recovering Bonneville Federal payment obligation over the two-year rate period. The 2010-2011 Initial Power Rate Proposal includes a proposal to continue using a CRAC, which would enable Bonneville to increase rate levels at the beginning of the first year of the two-year rate period and one-time halfway through the rate period to obtain up to an additional $300 million in revenues from Preference Customers in the related fiscal year. The CRAC would trigger for all of Fiscal Year 2010 if Bonneville were to forecast, in approximately September 2009, that its accumulated modified net revenues indicate that its reserves attributed to Power Services are likely to drop below $750 million. This would enable Bonneville to increase revenues by means of the CRAC to address possible changes in financial condition that were to arise after the formal rate development process for the 2010-2011 Final Power Rate Proposal has closed. The CRAC would also trigger for all of Fiscal Year 2011 if Bonneville were to forecast, in approximately September 2010, that its accumulated modified net revenues indicate that its reserves attributed to Power Services are likely to drop below $750 million. The proposed CRAC is similar to the CRAC included in Bonneville's 2007-2009 Power Rate Proposal, as supplemented by the 2008 Supplemental Power Proposal, under which Bonneville is currently operating.

The initial power rate proposal proposes to continue a modified version of the NFB Adjustment included in Bonneville's 2007-2009 Power Rate Proposal, as supplemented by the 2008 Supplemental Power Rate Proposal. Under the new proposed NFB Adjustment, the CRAC cap of $300 million in additional revenues would be subject to increase to cover the costs of certain potential adverse events related to the current litigation over the 2008 Columbia River System Biological Opinion, should such events occur. These potential events relate primarily to the risk that the court may order changes in hydro-operations that decrease power sales or increase power purchases. The 2010-2011 Initial Power Rate Proposal also proposes to continue an updated modified version of NFB Emergency Surcharge that is in Bonneville's 2007-2009 Power Rate Proposal, as supplemented by the 2008 Supplemental Power Rate Proposal. This surcharge would allow Bonneville to increase power rates at any time in the 2010-2011 Rate Period to cover certain costs that could arise from the litigation over the 2008 Columbia River System Biological Opinion, provided that

Bonneville determines that its Treasury payment probability has fallen below 80 percent for the fiscal year in which the costs arise.

The 2010-2011 Initial Power Rate Proposal also proposes to continue an updated version of the Dividend Distribution Clause, which would provide rebates to Preference Customers in Fiscal Year 2011 to the extent that Bonneville forecasts near the end of Fiscal Year 2010 that its accumulated modified net revenues indicate that its reserves attributed to Power Services at the end of Fiscal Year 2010 will be greater that $1,050 million. Bonneville is evaluating the potential rate level benefits of extending the Flexible PF Rate Program into Fiscal Years 2010 and 2011. The extension of the Flexible PF Program (in addition to the $300 million line of credit for operating expenses that Bonneville established in Fiscal Year 2008 with the United States Treasury) may enable Bonneville to propose rate levels under the Final 2010-2011 Power Rate Proposal that are lower than would otherwise be the case. See "BONNEVILLE FINANCIAL OPERATIONS—Banking Relationship between the United States Treasury and Bonneville."

Relationship to Transmission Rates. Bonneville's power and transmission rates processes are being run concurrently. Under Bonneville's initial proposals for power and transmission rates, the average cost of delivered power rates (power rates plus transmission rates) for Preference Customers would increase by about 7.5 percent over current combined rates.

In order to provide ancillary and control area services to its customers, Transmission Services obtains generation support from Power Services. Power Services establishes a per unit charge for the generation reserves it provides to Transmission Services for these purposes and Transmission Services develops rates for wind integration (among other services), which rates seek to recover the costs of the generation support obtained from Power Services.

With the influx of wind resources on the Federal Transmission system, the need for generation reserves has significantly increased. During the pendency of the power and transmission rate case proceedings, Bonneville expects to refine its assumptions about how much wind will be added in its control area, the appropriate allocation of the net costs of generation reserves between wind generators and power loads, forecasts of the need for generation reserves if any, and the efficacy of operational controls that could limit the need for generation reserves. Bonneville assumed in developing the 2010-2011 Initial Power Rate Proposal that the revenue credit from Transmission Services to Power Services would be about $195 million over the two-year rate period, but in light of expectations that the final expected revenue credit would ultimately be reduced, as an adjustment to the initial power rate proposal, Bonneville included an assumed reduction in the expected revenue credit of about $34 million. In view of the foregoing open issues, it is possible that the assumptions Bonneville made with respect to the generation reserves revenue credit in the 2010-2011 Initial Power Rate Proposal could differ from the revenue credit assumptions Bonneville ultimately includes in the 2010-2011 Final Power Rate Proposal. See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

Recovery of Stranded Power Function Costs

As a consequence of regulatory and economic changes in electric power markets, many utilities see potential for certain of their costs, in particular power system costs, to become unrecoverable, *i.e.,* "stranded." Stranded costs may arise where power customers are able, pursuant to new open transmission access rules, to reach new sources of supply, leaving behind unamortized power system costs incurred on their behalf. Bonneville could also face this concern. While Bonneville has separate statutory authority requiring it to assure that its revenues are sufficient to recover all of its costs, additional authority may be required to assure that such costs, including Bonneville's payments to the United States Treasury, are made on time and in full. Depending on the exact nature of wholesale and retail transmission access, it is possible that Bonneville's power marketing function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. 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 FPA 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 FPA. For a discussion of Order 888 and sections 211/212 of the FPA, as amended by EPA-1992, see "TRANSMISSION SERVICES—Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services."

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211/212 of the FPA are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest

Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under sections 211/212.

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

Under EPA-2005, FERC was granted authority to require that the rates for transmission service that Bonneville provides to itself be comparable to the rates it charges others. The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act. 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, notwithstanding the enactment of EPA-2005. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

TRANSMISSION SERVICES

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 23 percent of Bonneville's revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2008.

Bonneville's Transmission Services provides transmission service under FERC's *pro forma* Open Access Transmission Tariff. Two reservation based 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. Network Integration service is used by many Bonneville Preference Customers for delivery of primarily Federal power to their loads. Point-to-Point service is taken typically by marketers, independent power producers and certain large utility customers. Finally, Bonneville, as a partial owner of the northern portions of Southern Intertie and southern portions of certain transmission lines connecting areas of western Canada with the Region, provides Point-to-Point service to power marketers, including Bonneville's Power Services, which use Bonneville transmission service to effect power sales and related transactions inside and outside the Region. Bonneville's Transmission Services also provides reservation-based service under "legacy contracts" that were in effect when Bonneville adopted open access in the mid-1990's. As these contracts expire, the service converts to open access.

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. These customers pay roughly $4.00 to $4.50 per megawatt hour for Network Integration transmission and all ancillary services to provide delivery of firm power that Bonneville sells at the PF Rate, which is currently priced at roughly $27 to $33 per megawatt hour, depending on type of service and exclusive of transmission. Other customers, such as Regional IOUs, and extra-Regional utilities, and marketers using Point-to-Point service to transmit non-Federal power, pay a fixed monthly charge of approximately $1.80 to $2.50 per megawatt hour for transmission and two required ancillary services, the effective rate for which depends on the actual transmission usage.

Bonneville's Transmission System

The Federal System includes the transmission system that is owned, operated and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-Federal power resources. Bonneville's transmission system (also referred to as the "Federal transmission system") is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 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 percent 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 4,800 megawatts of capacity, and in the south to north direction is 3,675 megawatts of capacity. The rated transfer capability of the DC line in both directions is 3,100 megawatts. The operating transfer capability (or reliability transfer capability) of these facilities varies by generation patterns, weather conditions, load conditions and system outages.

The Federal transmission system is used to deliver Federal and non-Federal power between resources and loads within the Pacific Northwest, and to import and export power from and to adjacent regions. Bonneville's Transmission Services provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Services 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, maintenance, and expansion to maintain electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by internal, regional and national reliability practices. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005" for a discussion of new statutory provisions relating to reliability criteria.

Bonneville continually monitors its transmission system and evaluates cost-effective reinforcements needed to maintain electrical stability and reliability of the system 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. For example, operating conditions such as weather, system outages and changes in generation and load patterns may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of users of the Federal transmission system, including Bonneville's Power Services. To assure that Bonneville's transmission system is adequate to meet transmission needs, Transmission Services evaluates system performance to determine whether or not to make transmission infrastructure investments.

While in the recent past Bonneville has focused its transmission infrastructure efforts on transmission projects needed to maintain reliability, other transmission projects are now being undertaken or proposed that will provide additional, long-term firm transmission service for those seeking new transmission service in the Region, especially those developing new power generation projects both inside and outside the Region. Under Bonneville's policies, certain qualifying entities, referred to as "Eligible Customers," may request that Bonneville provide transmission service across the Federal transmission system and in some circumstances, Bonneville may have to build or install transmission facilities to provide the requested transmission service. Bonneville does not believe that it is subject to FERC regulation in the funding of such investments; nonetheless, as a policy matter Bonneville has sought FERC findings that BPA's policies and tariff terms relating to providing transmission service are consistent with FERC policy.

Depending on the circumstances, Bonneville may seek prepayment of its costs for the related investments from the Eligible Customers seeking the transmission service. In many such instances, in particular where the related facilities are included in Bonneville's network, Bonneville may return, over time, to the Eligible Customers the amounts they advanced to Bonneville for the related new facilities. Bonneville may provide these returns in the form of (i) credits against billings by Bonneville for firm transmission service purchased from Bonneville at established transmission rates, or (ii) in the case of new facilities to interconnect large new generation projects to the network, cash payments to the generator or its assigns. The payments and credits by Bonneville are intended to permit the Eligible Customer to recoup the funds it provides to Bonneville.

In some circumstances, Bonneville may not seek any prepayment for transmission investments from the Eligible Customer and may allocate all of the costs of new facilities to network service rates, thereby socializing the costs among all network customers. Even where Bonneville does not seek prepayment, Bonneville may determine to charge the Eligible Customer an "incremental cost" rate for transmission service, which is higher than Bonneville's embedded cost rate, in order for Bonneville to protect other customers from costs they would otherwise bear due to the provision by Bonneville of the new service. Bonneville may allocate some of the facilities' costs to other network customers under embedded cost rates if they are benefited by the new facilities, in particular where the new facilities lead to the avoidance of construction of other new facilities for reliability purposes.

FERC has approved a proposal by Bonneville through which Bonneville will seek to identify the extent Eligible Customers, including developers of proposed new generation, such as wind generation, will actually make long-term, creditworthy commitments for transmission service that require new network transmission system investments.

Bonneville believes that this process will assist Bonneville in assuring it will recover the costs of investing in related transmission facilities and help avoid stranded transmission investments.

As this process unfolds, and Bonneville identifies the potential for financing such investment with means other than the customer-funded approaches relied on in the past, Bonneville may incur new, indirect, non-Federal debt obligations. Bonneville is unable to predict the cost of new investments for the integration of new generation or to meet other Eligible Customers' transmission service requests, the amount that will actually be committed to by Eligible Customers on terms acceptable to Bonneville, or the extent to which Bonneville will fund such investments through customer advances of funds, borrowing from the United States Treasury, or third-party debt, such as lease-purchases.

In Fiscal Year 2008, Bonneville provided about $11 million in transmission payment credits as offsets for amounts advanced to Bonneville for new transmission integration investments. Bonneville expects that the amount of such credits could increase in coming years because of expected increases in the development of generation projects (particularly wind projects) that will need transmission service over the Federal transmission system.

Bonneville's current transmission system investment plan calls for Bonneville to make investments in Fiscal Years 2009 through 2014 averaging about $470 million annually. To finance the foregoing investments, Bonneville expects to use United States Treasury borrowing, reserves and advance payments from generation integration and transmission customers. Bonneville also expects to use long-term, capitalized lease-purchase arrangements to acquire transmission infrastructure facilities as a means of reducing the pressure on Bonneville's United States Treasury borrowing authority. With DOE policy approval, Bonneville entered into a long-term, capitalized lease agreement with Northwest Infrastructure Financing Corporation ("NIFC") in 2003 with respect to a large transmission line project located in Washington State. NIFC issued about $120 million in bonds to fund construction of the project. The bonds are secured solely by NIFC's pledge of Bonneville's lease payments under the project lease.

With DOE policy approval, Bonneville entered into a master lease arrangement in Fiscal Year 2007 with an affiliate of NIFC II to lease finance up to $90 million in transmission replacements and improvements to the Federal System. Subsequently, Bonneville and two separate affiliates of NIFC entered into two separate master lease agreements to lease finance an aggregate $300 million in transmission replacements and improvements to the Federal System. Under each of the master lease arrangements, Bonneville's lease payments are pledged to the payment of bank loans incurred by the respective project owner. The proceeds of the loans are used to finance the construction and installation of the leased facilities. Bonneville's lease payments are not conditioned on the completion, suspension or termination of the related projects and the principal amounts associated with the bank loans are included in Federal System audited financial statements as "Non-Federal Debt." The 2009 Congressional Budget Submission includes potential Bonneville third-party estimates averaging about $167 million annually over Fiscal Years 2008-2013. The actual value could be higher or lower depending on capital spending in such years. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville's Financial Plan."

Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services

In general, the thrust of regulatory changes in the 1990s, both by Congress and FERC, has been to require 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 FPA 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 or preferential.

While Bonneville is not generally subject to the FPA, Bonneville is a "transmitting utility" under the EPA-1992 amendments to sections 211/212 of the FPA. 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 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 offers open access in return, either through bilateral contracts or by submitting to FERC for its approval (i) an open access transmission tariff that substantially conforms to the *pro forma* tariff and (ii) adopting transmission rates for third parties 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, since 1996, Bonneville has 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 Services and other transmission users at the same tariff terms and conditions, and at the same rates. Bonneville's current open access transmission tariff became effective October 1, 2001 and, as amended, remains in effect indefinitely. The tariff has received FERC approval. Bonneville will continue to update the tariff as appropriate to reflect changes FERC makes to its *pro forma* open access tariff. Bonneville is in the process of adopting changes in its tariff to reflect relatively recent changes in FERC's *pro forma* tariff.

EPA-2005 includes provisions relating to terms and conditions of transmission service that may be imposed by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services to others on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

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. Although Bonneville is not subject to Order 889, non-jurisdictional utilities must adhere to it in order to obtain reciprocity. Therefore, Bonneville has separated its transmission and power functions into separate business units in conformance with that order and has developed and submitted standards of conduct for FERC's review. FERC has concluded that Bonneville's standards of conduct are acceptable.

Bonneville's Transmission and Ancillary Services Rates

Under the Northwest Power Act, Bonneville's transmission rates are set in accordance with sound business principles to recover the costs 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 related 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 proposed and FERC has approved as final Bonneville's transmission and ancillary services rates for the two years beginning Fiscal Year 2008. The transmission and ancillary services rates maintain approximately the same rates, on average, as the rates immediately theretofore in effect. Ancillary services are services that ensure reliability and support the transmission of electricity, primarily from generation sites to customer loads. Such services may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

Bonneville is in the process of developing a final rate proposal for transmission and ancillary services for the two fiscal years beginning October 1, 2009. Bonneville has prepared a draft settlement agreement reflecting a tentative agreement with its customers to continue current transmission rates with certain limited changes. The proposal would not settle certain ancillary services that are particularly important to the integration of wind generation. All issues concerning these services, including the amount and pricing of the reserve capacity needed for such services, will be addressed in Bonneville's power rate proceeding for the Fiscal Year 2010-11 Rate Period. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2010 through 2011—Relationship to Transmission Rates." All issues concerning rate design and the rate schedules for these services will be addressed in Bonneville's transmission rate proceeding. Bonneville has issued an initial transmission and ancillary rates proposal reflecting the draft settlement and expects to complete the transmission rates process and submit its final proposed rates for transmission and ancillary services, together with the related record of decision, to FERC in July of 2009.

EPA-2005 includes provisions relating to transmission rates charged by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services at rates "comparable" to those the utility charges itself. Thus, FERC now has authority to require that the transmission rates Bonneville charges Power Services for transmission service to be comparable to the transmission rates Bonneville charges other customers. FERC has not yet invoked this authority. However, Bonneville has sought and received FERC approval of transmission rates under comparability standards, and with the stricter rates standards applicable to reciprocity under Order 888, since 1996.

The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act to establish transmission rates to recover Bonneville's transmission costs. In the opinion of General Counsel to Bonneville, the foregoing EPA-2005 provisions relating to Bonneville's transmission rates would not adversely affect Bonneville's authority and obligation to recover in full the costs of providing transmission service through its transmission rates. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Bonneville's Participation in a Regional Transmission Organization

In January 2000, FERC issued a final rule on regional transmission organizations ("RTOs"), establishing minimum characteristics and functions for an RTO and requiring that each jurisdictional utility (a term that does not include Bonneville) make certain filings regarding the formation of and participation in an RTO. FERC proposed RTOs as a means to assure that transmission owners make transmission available on a basis that does not discriminate in favor of their affiliated power marketing activities. Following the FERC actions to promote RTOs, transmission owning utilities in the Region and others attempted to develop an RTO that would assist transmission operations in the Region. None of those proposals have been implemented. FERC has now decided that participation in RTOs will be voluntary. EPA-2005 includes provisions explicitly authorizing Bonneville to participate in the formation and operation of an RTO. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Bonneville is currently pursuing an approach to implement "ColumbiaGrid," with six transmission owners that are control area operators in the West. Compared to prior RTOs that have been proposed for the Region, ColumbiaGrid would not qualify as an "RTO" under FERC policies since ColumbiaGrid would have a relatively restricted scope of operations. By contrast to an RTO, ColumbiaGrid focuses on coordinating Regional transmission planning and expansion, assisting participating utilities in meeting their transmission reliability obligations, and operating an information system ("OASIS") to provide power marketers and others with information about transmission system operations. It is possible in the long run that ColumbiaGrid would have increased operational control of the related transmission assets and take an increased role in providing transmission service, including through the operation of transmission markets and market monitoring. Whether ColumbiaGrid's scope of operations evolves to include new functions will be determined by the participating utilities in the future.

Bonneville has entered into agreements to fund a proportionate interest of the costs of making ColumbiaGrid operational, to assist ColumbiaGrid in efficient transmission planning and expansion in its service area, and to operate a common OASIS with implementation beginning in 2009. Bonneville's estimates that its expense associated with the foregoing and other existing arrangements with ColumbiaGrid will be about $3 million per year.

ColumbiaGrid and its members are also participating with the members of two other groups of transmission owners in a "Joint Initiative," which is exploring approaches to deal with the challenges associated with integrating large amounts of intermittent generating resources, such as wind power, into the resource mix within the transmission system of Western North America. The provision of ancillary services to support these resources can be managed by certain, more efficient scheduling practices, which can be achieved only by the development of communication protocols and business practices within and across Western control areas. Bonneville hopes that agreements to implement the results of this Joint Initiative will be executed in calendar year 2009.

MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES

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 under the Northwest Power Act 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.

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 power rates, FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a power 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 power 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.

For a discussion of FERC rate review and regulation related to transmission access and rates, see "TRANSMISSION SERVICES—Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services" and "—Bonneville's Transmission and Ancillary Service Rates."

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 Preference and certain Federal agency customers; (2) to DSIs; and (3) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for power sold to these respective customer 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.

Surplus Energy

Energy that is surplus to the contracted-for requirements of Bonneville's Regional customers is priced in accordance with the statutory standards (contained in the Northwest Power Act) applicable to such sales, as discussed above. Such energy is available within and without the Pacific Northwest, with most sales being made to California markets.

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. Bonneville has been identified as one of several potentially responsible parties at one site. Bonneville's environmental protection costs at this site are $100,000 to date. Additional costs for the remedial investigation at the site are possible during 2009. Bonneville has not committed to any cleanup at this time pending a Record of Decision in 2009. EPA estimates of potential cleanup costs are $1-2 million, which would be shared among a number of parties.

Energy Policy Act of 2005

EPA-2005 was enacted by Congress in July 2005. Among other things, EPA-2005 amended the Federal Power Act ("FPA") by including new provisions applicable to Bonneville's power and transmission marketing. Provisions in EPA-2005 that could have the greatest impact on Bonneville's operations include the following:

(i) EPA-2005 amends the FPA to authorize FERC to require an "unregulated transmitting utility" (a term that includes Bonneville) to provide transmission services at rates comparable to those the utility charges itself, and on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. Although Bonneville is uncertain how FERC will apply its new authority (for instance, the reporting or filing requirements FERC might impose or how FERC might interpret the provision), since 1996 Bonneville has voluntarily adopted terms and conditions for non-discriminatory open access transmission services through a FERC-filed tariff, offering transmission service to Bonneville's Power Services and other transmission users at the same tariff terms and conditions, and at the same rates. See "TRANSMISSION SERVICES—Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services."

(ii) With respect to Bonneville's participation in a regional transmission organization, EPA-2005 authorizes the Secretary of Energy or, upon designation by the Secretary, the administrator of a power marketing administration ("PMA") including Bonneville, to transfer control and use of the PMA's transmission system to certain defined entities, including a regional transmission organization, independent system operator, or any other transmission organization approved by FERC for operation of transmission facilities. The section further provides that the contract, agreement, or arrangement by which control and use is transferred must include provisions that ensure recovery of all of the costs and expenses of the PMA related to the transmission facilities subject to the transfer, consistency with existing contracts and third-party financing arrangements, and consistency with the statutory authorities, obligations, and limitations of the PMA. See "TRANSMISSION SERVICES—Bonneville's Participation in a Regional Transmission Organization."

(iii) EPA-2005 grants FERC limited authority to order refunds in the case of certain energy sales by non-jurisdictional utilities such as Bonneville. The refund authority is limited to sales of 31 days or less made through an organized market in which the rates for the sale are established by a FERC-approved tariff. The refund authority applies to Bonneville only if the rate for the sale by Bonneville is unjust and unreasonable and is higher than the highest just and reasonable rate charged by any other entity for a sale in the same geographic market for the same or most nearly comparable time period. See "POWER SERVICES—Customers and Other Power Contract Parties of Bonneville's Power Services—Effect on Bonneville of Developments in California Power Markets in 1999-2001."

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue and enforce mandatory reliability rules that cover all users, owners and operators of the bulk power system. The provision would apply to Bonneville, but the Act expressly states that neither the ERO nor FERC are authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.

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 a Canadian counterpart, 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 specified point unless the United States Entity and the Canadian Entity agree to other arrangements. The United States Entity and Canadian Entity reached such an agreement in the late 1990s, and as a result the United States Entity does not have to build a transmission line to assure delivery to the point referred to in the Treaty.

The United States Entity and Canadian Entity 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 in 1999.

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 Bonneville's 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 or submitted to Congress have included privatizing the Federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at Federal hydroelectric projects, studying the removal of certain federally-owned dams of the Federal System, placing caps on Bonneville's authority to incur certain types of capitalized costs, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates, and limiting Bonneville's ability to incur new third party debt and issue new bonds to the United States Treasury to a maximum in aggregate not in excess of a single aggregate amount equal to Bonneville's then-available United States Treasury borrowing authority, which, at the time, was $4.45 billion. None of these bills or proposals was enacted into law.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted or implemented. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such future proposals, if enacted or implemented, could affect Bonneville's ability to perform its obligations with respect to the Series 2009 Bonds.

Bonneville is a Federal agency. It is subject to direction or guidance in a number of respects from the United States Office of Management and Budget, DOE, FERC, the United States Treasury and other Federal agencies. Bonneville is frequently the subject of, or would otherwise be 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, 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 United States 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 and other law, 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 certain major generating or conservation resources.

The Federal System Investment

The total cost of the multipurpose Corps and Reclamation projects that are part of the Federal System 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 Reclamation 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 and certain capital conservation and fish and wildlife costs since 1980 have been funded in great part through the use of Bonneville's borrowing authority with the United States Treasury.

Bonneville is required by statute to establish rates that are sufficient to repay the Federal investment in the power facilities of the Federal System within a reasonable period of years. The statutes, however, are not specific with regard to directives for the repayment of the Federal System investment, including what constitutes a reasonable period of years. Consequently, the details of the repayment policy have been established through administrative interpretation of the basic statutory requirements. The current administrative interpretation is embodied in the United States Secretary of Energy's directive RA 6120.2. The directive provides that Bonneville must establish rates that are sufficient to repay the Federal investments within the average expected service life of the facility or 50 years, whichever is less. Bonneville develops a repayment schedule both to comply with investment due dates and to minimize costs over the repayment period. Costs are minimized, in accordance with the United States Secretary of Energy's directive RA 6120.2, by repaying the highest interest-bearing investments first, to the extent possible. This method of determining the repayment schedule would result in some investments being repaid before their due dates, while assuring that all investments will be repaid by their due dates. As of September 30, 2008, Bonneville had repaid $9.1 billion of principal of the Federal System investment and has $4.3 billion principal amount outstanding with regard to such appropriated investments and $2.19 billion principal outstanding in bonds issued by Bonneville to the United States Treasury.

Bonneville Borrowing Authority

Bonneville is authorized to issue and sell to the Secretary of Treasury, and to have outstanding at any one time, up to $7.7 billion aggregate principal amount of bonds. Of the $7.7 billion in borrowing authority that Bonneville has with the United States Treasury, $2.19 billion of bonds were outstanding as of September 30, 2008. 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 $7.7 billion in United States Treasury borrowing authority, $1.25 billion is available for electric power conservation and renewable resources, including capital investment at the Federal System hydroelectric facilities owned by the Corps and Reclamation, and $6.45 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable Federal Government institutions at the time of issuance. As of September 30, 2008, the interest rates on the outstanding bonds ranged from 2.85 percent to 8.55 percent with a weighted average interest rate of approximately 5.22 percent. The original terms of the outstanding bonds vary from 3 to 34 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 Reclamation capital investments, up to 20 years for conservation investments and 15 years for fish and wildlife projects. Bonds can be issued with call options. As of September 30, 2008, Bonneville had eight callable bonds on its books totaling $389 million.

Banking Relationship between the United States Treasury and Bonneville

Effective April 30, 2008, Bonneville entered into an Obligation Purchase Memorandum of Understanding ("Obligation Purchase MOU") establishing a new banking arrangement governing the terms by which Bonneville borrows from the United States Treasury. Formerly, there was no overarching formal documentation of the terms under which the United States Treasury would lend funds to Bonneville; rather, the banking arrangement was more informal with borrowings made on the basis of administrative practice evolved over more than 30 years. The new banking arrangement provides a process and methodology for establishing interest rates, various types of credit facilities, the terms for several types of prepayment rights, the documentation requirements for requesting advances and rescinding advances requests, and a number of other administrative details. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $300 million in aggregate. The short-term operating advances can be made available on as short as one day's notice and have a maximum repayment period of one year, although Bonneville may extend the maturities an additional year by exercising certain rights that would re-establish applicable interest rates. Nothing in the new banking arrangement increases the statutory limit on the $7.7 billion aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time.

Coincident with the entry into the Obligation Purchase MOU, Bonneville and the United States Treasury entered into an Investment Memorandum of Understanding ("Investment MOU") that governs investments in the Bonneville Fund beginning October 1, 2008. Under prior practice, Bonneville earned a credit on all cash balances in the Bonneville Fund, which credits were to be applied to interest due on Bonneville's outstanding United States Treasury bonds. The interest credit was earned at the weighted average interest rate of all outstanding bonds issued by Bonneville to the United States Treasury. Under the Investment MOU, Bonneville's ability to earn interest credits will phase-out gradually over an expected ten-year period, beginning on October 1, 2008. In lieu of earning interest credits, Bonneville will invest the applicable cash reserves in the Bonneville Fund in certain interest bearing securities issued by the Treasury. Bonneville expects that the fund balance interest earnings under the investment model will be lower than if Bonneville were to continue to earn interest credits on all of its balances under the prior practice.

Debt Optimization Program

In 2000, Bonneville presented a "Debt Optimization Program" to Energy Northwest. The Debt Optimization Program, which was agreed to by Energy Northwest, involves extending the final maturities of outstanding Columbia Project Net Billed Bonds coming due prior to 2013 through a series of refunding bond issues. In 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 by extending the maturity of such bonds for any future refinancing of such bonds. In addition, in early 2006 Energy Northwest and Bonneville agreed that certain bonds to be issued to finance new investments at the Columbia Generating Station, and certain new Columbia Generating Station refunding bonds, may have maturities through 2024. A portion of such refunding bonds was issued in connection with the Debt Optimization Program.

Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's ratepayers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs and minimize costs to ratepayers; and (3) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. Implementing the Debt Optimization Program is intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's United States Treasury debt and reduce Bonneville's overall fixed costs. Under the Debt Optimization Program through Fiscal Year 2008, approximately $2.4 billion in maturing and advance refundable bonds issued by Energy Northwest for the Net Billed Projects have been refinanced with new bonds having final maturities in calendar years 2013-2024. Bonneville expects that Energy Northwest will continue to undertake similar refundings through at least Fiscal Year 2009.

Order in Which Bonneville's Costs Are Met

Bonneville's operating revenues include amounts equal to net billing credits provided by Bonneville under the Net Billing Agreements, as described in the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements." Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Net Billing Agreements for the Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. (Bonneville and Energy Northwest have entered into agreements that obligate Bonneville to pay the costs of the Net Billed Projects on a current cash basis and in most circumstances would reduce the use of net billing to meet the costs of the Net Billed Projects. See "—Direct Pay Agreements.")

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 Reclamation 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 2008 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $963 million in Fiscal Year 2008, approximately $210.5 million was 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 the Debt Optimization Program through the use of cash flows derived from reduced debt service in such fiscal year for the Project 1, Project 3 and the Columbia Generating Station. Such United States 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 Program, Bonneville plans to make similar advance amortization payments to the United States Treasury in Fiscal Year 2009 and at least through Fiscal Year 2012. See "—Debt Optimization Program."

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 non-United States Treasury cash payment obligations of Bonneville, including: cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2009 Bonds; payments, if any, under the 1989 Letter Agreement; payments under the Direct Pay Agreements; and, other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments under the Net Billing Agreements securing the Series 2009 Bonds, payments, if any, under the 1989 Letter Agreement, payments under the Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—General" and "—Direct Pay Agreements" and see "—Direct Pay Agreements" in this Appendix A.

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 with Net Billing Agreement Participants ("Participants") requiring net billing to fund resource acquisitions or other capital program investments. For a description of the Net Billing Agreements, net billing and Participants, see the Official Statement under "SECURITY FOR THE NET BILLED BONDS."

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 Pay Agreements

As part of the preparatory work leading to the 2007-2009 Power Rate Proposal, Bonneville and Regional power customers explored various proposals to reduce proposed rate levels for the 2007-2009 Rate Period while maintaining an acceptably high probability that Bonneville will meet its United States Treasury payment obligations on time and in full. Discussions focused on finding means to assure that Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both Federal and non-Federal. As a result of the foregoing discussions, in Fiscal Year 2006, Bonneville and Energy Northwest entered into certain Direct Pay Agreements. Under these agreements, Bonneville has agreed by contract to pay directly to Energy Northwest the costs of Columbia Generating Station, Project 1 and Project 3 as billed to Bonneville by Energy Northwest.

In reliance on Bonneville's Direct Pay Agreement obligations, the billing statements that Energy Northwest is required to provide to Participants under the Net Billing Agreements show and will show the expected payments from Bonneville under the Direct Pay Agreements as amounts payable from sources other than the Net Billing Agreements. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Payment Procedures." Thus, the amounts to be paid by Participants to Energy Northwest in a Net Billing Agreement Contract Year have begun to be and will in the future be reduced to zero, thereby reducing Bonneville's obligation to provide net billing credits to zero as well. In this manner, Bonneville meets and will meet Net Billed Project costs on a current basis entirely by means of cash payments from the Bonneville Fund.

By reducing the amount of net billing credits, Bonneville receives and will receive more revenues in cash from Participants during times of the year when Bonneville would otherwise carry its lowest annual cash balances, typically after Bonneville makes its end-of-fiscal-year payments to the United States Treasury. Under the Direct Pay Agreements, Energy Northwest's revenues with respect to the Net Billed Projects are and will be received throughout the year rather than predominantly in the early months of Energy Northwest's fiscal year (July 1 – June 30), and have resulted and will result in higher cash balances in the Bonneville Fund at the end of each Bonneville fiscal year. Bonneville estimates that, as a consequence of re-shaping its annual cash flow patterns under the Direct Pay Agreements, Bonneville lowered its 2007-2009 Power Rate Proposal by between five percent and ten percent from the levels that would have been expected in the absence of the Direct Pay Agreements.

The Direct Pay Agreements did not and do not result in the amendment or termination of the Net Billing Agreements or any other agreements of Bonneville with respect to the Columbia Generating Station, Project 1 or Project 3, including the 1989 Letter Agreement, the Voluntary Cash Payment Agreements and the Assignment Agreements, each as described in the Official Statement under "SECURITY FOR THE NET BILLED BONDS." The Participants' obligations to pay for power purchased from Bonneville did not and do not change as a result of the Direct Pay Agreements. The effect of the agreements is that the Participants no longer pay such amounts to Energy Northwest (with resulting net billing credits from Bonneville) for the period that the Direct Pay Agreements remain in effect. Rather, the Participants pay their billings by Bonneville for power and transmission services to Bonneville. The Direct Pay Agreements provide that, in the event that Bonneville were to fail to make required payments under the Direct Pay Agreements, Energy Northwest would re-initiate net billing as required under the Net Billing Agreements.

Although the payments to Energy Northwest under the Direct Pay Agreements remain included under the respective pledge of revenues for related series of Net Billed Bonds, such agreements are not pledged to secure the payment of, nor are they security for, the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

In the event that payments under the Direct Pay Agreements were to fall short of meeting Net Billed Project costs or the Direct Payment Agreements were terminated, under the Net Billing Agreements, the Participants would resume making payments directly to Energy Northwest and Bonneville would resume crediting (net billing) amounts otherwise due to Bonneville by the Participants for power and transmission purchases from Bonneville, up to the amount of payments made by the Participants to Energy Northwest. See, in the Official Statement, "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Payment Procedures." In general, the amount of the Participants' payments subject to net billing is based on the amount of transmission and power purchased from Bonneville and the rates levels charged by Bonneville for such purchases.

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 Reclamation and the 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 Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for the Corps, Reclamation, and the Fish and Wildlife Service in Fiscal Year 2008 were \$155 million, \$70 million, and \$18 million, respectively.

Bonneville believes that, in contrast to prior practice, the direct funding 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 is 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 funding 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 funding could be made to the exclusion of non-Federal payments that would otherwise have been paid under historical practice. A result of any direct funding obligation by Bonneville is that there has been and will 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, Bonneville expects to have roughly $600 million to $950 million in scheduled payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses through Fiscal Year 2013. Bonneville expects that it will renew and extend the direct funding agreements with the Corps, Reclamation and Fish and Wildlife Service prior to the expiration dates of the respective agreements.

Position Management and Derivative Instrument Activities and Policies

Bonneville seeks to ensure that its management of various financial risks be conducted in a controlled, business-like manner. To this end, Bonneville has adopted risk management policies and organizational structures that systematically address the management of these activities. Policies governing transacting are overseen by Bonneville's Transacting Risk Management Committee ("TRMC"), which is comprised of senior Bonneville executives.

Bonneville's policies allow the use of financial instruments such as commodity and interest rate futures, forwards, options and swaps to manage Bonneville's net revenue outcomes. Such policies do not authorize the use of financial instruments for purposes outside TRMC-established strategies. Strategies are established in the context of portfolio management, as opposed to individual position/exposure management, and are subject to quantitatively derived hard position limits mathematically linked to Bonneville's financial metrics, such as United States Treasury payment probability. Exceptions to established policies must be cleared by the TRMC before execution.

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 are in an aggregate notional principal amount approximately equal to the principal amount of certain variable rate bonds issued by Energy Northwest (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, with a notional amount of $300 million, will expire in Fiscal Year 2013, and the other, with a notional amount of $200 million, will expire in Fiscal Year 2018. The Related Bonds are variable rate bonds having final maturities in calendar years 2016, 2017 and 2018. 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. The swap provider for the swap having the Fiscal Year 2018 expiration date is currently rated "Aa3" by Moody's Investor Service ("Moody's") and A+ by Standard & Poor's Credit Market Services, a Division of The McGraw-Hill Companies, Inc. ("S&P"). The other swap provider is currently rated "Aaa" by Moody's and "AAA" by S&P.

Certain of the Series 2009 Bonds are being issued to refund approximately $100 million of Related Bonds and in connection with such issuance Bonneville has terminated a like notional amount of the fixed interest swaps having the Fiscal Year 2018 expiration date, described immediately above. See "PURPOSE OF ISSUANCE—Refunding Bonds" in the Official Statement. To partially terminate the swap, Bonneville has agreed to pay the swap provider about $8.2 million.

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2006 through 2008 are hereinafter set forth in the "Federal System Statement of Revenues and Expenses (unaudited)." Such data have been derived from the annual audited financial statements of the Federal System and differ therefrom in some respects in the categorization of certain costs. The audited Financial Statements of the Federal System (prepared in accordance with generally accepted accounting principles ("GAAP") and provided as Appendix B-1 to the Official Statement) include accounts of Bonneville as well as those of the generating facilities that are located in the Region and owned by the Corps and Reclamation and for which Bonneville is the power marketing agency.

The unaudited quarterly financial report for the three months ended December 31, 2008 is included as Appendix B-2. For a discussion of the quarterly financial report for the three months ended December 31, 2008, see "—Management Discussion of Unaudited Results for the Three Months Ended December 31, 2008."

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

Fiscal year ending September 30,	2008	2007	2006
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-owned utilities [1]	$ 1,504,637	$ 1,836,731	$ 1,711,889
Direct Service Industrial Customers	405	0	80,021
Northwest Investor-Owned Utilities	214,153	281,362	502,601
Sales outside the Northwest Region [2]	603,891	460,656	691,508
Book-outs [3]	(109,704)	(94,705)	(220,911)
Total Sales of Electric Power	2,213,382	2,484,044	2,765,108
Transmission [4]	721,513	689,287	641,132
Fish Credits and other revenues [5]	101,723	95,309	13,129
Total Operating Revenues	3,036,618	3,268,640	3,419,369
Operating Expenses:			
Bonneville O&M [6]	740,871	679,711	680,243
Purchased Power [3]	450,035	310,073	535,020
Corps, Reclamation and Fish & Wildlife O&M [7]	243,073	234,469	217,154
Non-Federal entities O&M — net billed [8]	231,457	271,826	226,856
Non-Federal entities O&M — non-net billed [9]	42,032	43,328	40,460
Total Operation and Maintenance	1,707,468	1,539,407	1,699,733
Net billed debt service	457,847	319,383	315,016
Non-net billed debt service	21,646	23,938	22,611
Non-Federal Projects Debt Service [10]	479,493	343,321	337,627
Federal Projects Depreciation	358,064	351,787	353,236
Residential Exchange [11]	(1,220)	340,170	156,167
Total Operating Expenses	2,543,805	2,574,685	2,546,763
Net Operating Revenues	492,813	693,955	872,606
Interest Expense:			
Appropriated Funds	262,108	279,120	269,884
Long-term debt	62,822	55,704	85,078
Capitalization Adjustment [12]	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(32,057)	(33,172)	(28,514)
Net Interest Expense	227,968	236,747	261,543
Net Revenues/(Expenses)	$ 264,845	$ 457,208	$ 611,063
Total Sales (unaudited) — average megawatts (Net of Residential Exchange Program)	9,283	9,374	10,226

(1) This customer group includes Preference Customers (municipalities, public utility districts and rural electric cooperatives in the Region) and Federal agencies.

(2) In general, revenues from sales outside the Northwest are highly dependent upon stream-flows in the Columbia River basin. Stream-flows directly impact the amount of seasonal surplus (secondary) energy available for sale, the costs of generating power with alternative fuels, and ultimately the price Bonneville can obtain for its exported seasonal surplus (secondary) energy and surplus firm power.

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance from the Emerging Issues Task Force ("EITF") of the Financial Accounting Standards Board ("FASB"). Under this guidance ("EITF 03-11") both revenues and expenses associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) are to be reported on a "net" basis in both operating revenues and purchased power expense.

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

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife credits (also referred to as "4(h)(10(C) credits") Bonneville receives in its United States Treasury repayment obligation. Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The amount of such credits was about $76 million, $66 million and $100 million in Fiscal Years 2006, 2007 and 2008, respectively. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." In addition, under FASB Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville reported a unrealized mark-to-market losses of $100.1 million, $6.5 million and $30.6 million in Fiscal Years 2006, 2007, and 2008 respectively. SFAS 133 requires (i) that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and (ii) that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. It is Bonneville's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended. 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 not required to be recorded at fair value in the financial statements. For all other derivative transactions Bonneville applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. Bonneville does not apply hedge accounting.

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

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

(8) 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 net billing agreements, which are capitalized contracts that cover the costs of certain generating resources, including Energy Northwest's Project 1, Project 3, and Columbia Generating Station.

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

(10) Non-Federal Projects Debt Service includes payments by Bonneville for all or a part of the generating capability of, and the related debt service, including interest, for 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 Eugene Water and Electric Board's ("EWEB") 30 percent ownership share of the Trojan Nuclear Project.

(11) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services" and "—Residential Exchange Program" and see "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2007." Bonneville suspended scheduled payments to Regional IOUs under the Residential Exchange Program Settlement Agreements when the agreements were invalidated by the Ninth Circuit Court in May 2007. Bonneville continued to accrue the scheduled-but-suspended-payments as an expense notwithstanding that the agreements were set aside. Bonneville did so on that basis that the suspended payments will eventually be paid, to Regional IOUs as Residential Exchange Program benefits and/or to Preference Customers as an over collection of rates. The aggregate amount of suspended payments under the Residential Exchange Program Settlement Agreements in Fiscal Year 2007 was $168 million. In Fiscal Year 2008, the amounts for prior years were adjusted through a rate case process and the accumulated effects of those adjustments and the current year expense are shown as the $1.2 million credit. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2008."

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

Management Discussion of Operating Results Presented in the Table "Federal System Statement of Revenues and Expenses."

Fiscal Year 2008

For Fiscal Year 2008, Federal System total operating revenues were $3.037 billion, a decrease of $232 million from Fiscal Year 2007. Power Services and Transmission Services combined gross sales decreased $224 million, or 7 percent, from the comparable period a year earlier. Power Services gross sales revenues decreased $256 million or 10 percent. The change was primarily due to the following key factors: In Fiscal Year 2008 there was a downward adjustment of $341 million due to the impacts of the rate proceeding on the Residential Exchange Program; there was a slight increase in long-term contractual obligations and sales under existing contracts resulting in a $24 million increase in revenues from firm power sales; due to a below-average water year and a delayed but rapid runoff, Bonneville purchased power in the spring to meet projected river operation needs and once these needs were met, remaining power was sold at a slightly higher price, resulting in a $61 million increase in surplus sales.

The $341 million downward adjustment in revenues reflects a $257 million refund of amounts to be returned to Preference Customers for over-collections from them by Bonneville in Fiscal Years 2007 and 2008 with respect to the Residential Exchange, plus the effects of the $67 million downward adjustment in revenues from Preference Customers as a result of the recoupment from Regional IOUs of a portion of overpayments made by Bonneville under the Residential Exchange Program Settlement Agreements in the fiscal years prior to Fiscal Year 2007 (Look-back Amount Offsets), and a downward adjustment in revenues from Preference Customers flowing from $17 million collected in rates in Fiscal Year 2003 for certain deferred Residential Exchange-related benefits to Regional IOUs.

Transmission Services gross sales increased $32 million, or 5 percent. The change was primarily due to the following key factors: network and intertie transmission sales and their associated ancillary services increased. Significant reasons for the increased revenues were the result of increased Point-to-Point and Intertie long-term and Point-to-Point short-term sales. There was also a slight increase in Point-to-Point and Intertie long-term rates from last fiscal year. The increase in revenues was offset by ancillary services primarily by elimination of revenues from customers using ancillary service product Reactive Supply and Voltage from Generation. This was a result of an agreement by Bonneville during the Transmission Services rate proceeding for rates and ancillary services for the two fiscal years beginning October 1, 2008.

The change in the unrealized fair value of Bonneville's derivative portfolio of $24 million was due to fluctuations in the forward price curves, physical delivery and a change in the overall portfolio mix. The change is primarily the result of a $17 million decrease in the value of swap agreements due to a decrease in the LIBOR index rate. Credits under Northwest Power Act section 4(h)(10)(C) increased $34 million, or 52 percent, in Fiscal Year 2008 when compared to the prior fiscal year as stream flows declined and market prices for purchased power increased. For a description of section 4(h)(10)(C) and related credits, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

In total operating expenses decreased $31 million, or 1 percent, from Fiscal Year 2007. The decline was the result of several factors. Residential Exchange expense decreased $341 million (arising from Bonneville's proposed downward re-determination of such benefit levels) as previously discussed above with respect to the decrease in Preference Customer revenues. To a large extent the decrease was offset by increases for purchased power and nonfederal projects debt service expense. Purchased power increased $140 million, or 45 percent, due to a combination of higher prices and increased purchases as a consequence of delayed runoff and the associated reduction in Federal System hydroelectric generation. Nonfederal projects debt service increased $136 million, or 40 percent, due to scheduled amortization of Energy Northwest bonds. The lower amortization for the prior period was the result of extension of nonfederal debt and early repayment of federal debt within Bonneville's total debt portfolio under the Debt Optimization Program. The overall objective of these debt management actions has been to achieve an optimal total debt portfolio. The portfolio includes federal appropriations, United States Treasury borrowings and nonfederal projects debt.

Net interest expense declined $9 million, or 4 percent. The primary reason for the decreased interest expense between years was a reduction of outstanding appropriated funds owed the United States Treasury. Interest on bonds issued to the United States Treasury declined $4 million as interest income increased $6 million due to earnings on higher cash balances in the Bonneville Fund.

Net revenues were $265 million in Fiscal Year 2008, a decrease of $192 million, or 42 percent, from Fiscal Year 2007 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions) were $157 million compared to $217 million in Fiscal Year 2007, representing a 28 percent decline. Bonneville believes that modified net revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues.

Fiscal Year 2007

For Fiscal Year 2007, Federal System total operating revenues were $3.269 billion, a decrease of $151 million from Fiscal Year 2006. Revenues from electricity and transmission sales for Fiscal Year 2007 were down $234 million, or 7 percent, from Fiscal Year 2006. Power revenues decreased $281 million, or 10 percent. Reduced stream flows and the bi-annual refueling of Columbia Generating Station nuclear power plant drove down generation. In addition, Bonneville had reduced power purchases. Therefore, less secondary energy was available for sale in Fiscal Year 2007. During Fiscal Year 2007, Bonneville provided monetary benefits rather than power to the DSIs. In contrast to prior years when Bonneville made certain power sales to certain Regional IOUs in connection with their Residential Exchange Program Settlement Agreements, in Fiscal Year 2007 Bonneville provided only monetary benefits rather than power in connection with the Residential Exchange Program. Transmission revenues increased $47 million, or 8 percent from Fiscal Year 2006 mainly due to increased sales under long-term point-to-point network and short-term contracts for transmission on the Southern Intertie. Load-based transmission sales to Preference Customers also increased due to greater than anticipated load growth. A small part of the increase in transmission service revenue is associated with revenues from Ancillary Services, which vary with the sale of transmission and are needed to ensure efficient and reliable service.

In total, operating expenses increased $28 million, or 1 percent, from Fiscal Year 2006. Purchased power decreased $225 million, or 42 percent, compared to Fiscal Year 2006. Purchased power decreased because a number of power purchase contracts entered into in the prior power rate period to meet greater than anticipated load expired at or before the end of Fiscal Year 2006. This reduction was offset to a degree by Residential Exchange benefits payments which increased $184 million, or 118 percent, from the prior fiscal year. Through Fiscal Year 2006, Residential Exchange Program benefits to Regional IOUs were provided through arrangements to purchase back certain previous power sales commitments to the Regional IOUs. The buy backs were made by Bonneville to meet other firm power sales obligations and the related payments by Bonneville were therefore included in Federal System financial statements as purchased power expense. Beginning with Fiscal Year 2007, all Residential Exchange Program benefits amounts were provided entirely through monetary payments pursuant to the Residential Exchange Program Settlement Agreements. (The Residential Exchange Program Settlement Agreements were set aside upon court review in May 2007 and Bonneville suspended related payments immediately thereafter). Net billed non-Federal entities O&M and net billed debt service increased $45 million and $4 million, respectively, due to bi-annual refueling of Columbia Generating Station and higher debt service expense for Energy Northwest.

Net interest expense for Fiscal Year 2007 decreased $25 million, or 9 percent, compared to Fiscal Year 2006. Interest expense on appropriated funds increased $9 million. Interest on bonds issued to the United States Treasury declined $5 million as interest income increased $24 million with higher cash balances. Allowance for funds used during construction increased $5 million as higher construction work in progress balances at Corps and Reclamation facilities of the Federal System offset to a degree by a decline resulting from the completion of a large transmission project, the Schultz Wautoma transmission line, in Fiscal Year 2006.

Net revenues were $457 million in Fiscal Year 2007, a decrease of $154 million, or 25 percent, from Fiscal Year 2006 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions.) were $217 million compared to $445 million in Fiscal Year 2006, representing a 51 percent decline.

Fiscal Year 2006

In Fiscal Year 2006, total operating revenues were $3.419 billion, an increase of $151 million from the prior fiscal year. Aggregate revenues from electricity and transmission sales for the Fiscal Year 2006 increased $318 million from one year earlier. Both Power Services and Transmission Services revenues increased. Power Services revenues increased due to a combination of factors, which include an increase in power sales to Preference Customers and significantly higher spot market power sales enabled by better than historical average precipitation and stream-flows in the Columbia River and Snake River basins coupled with strong market prices. Transmission Services revenues also increased due to the load growth and increased revenues from the Power Services in connection with surplus power sales discussed above and from the effects of a transmission rate increase of approximately 12.5 percent effective beginning in Fiscal Year 2005. SFAS 133 derivative mark-to-market amount for Fiscal Year 2006, decreased $195 million when compared to the prior year due to a drop in the forward prices, physical delivery and a change in the overall portfolio mix. In addition, miscellaneous revenues increased $9 million, or 14 percent, 4(h)(10)(C) credits increased $19 million, or 32 percent, in Fiscal Year 2006 when compared to the prior fiscal year.

In total, operating expenses increased $43 million, or two percent, from Fiscal Year 2005. The increase was a result of a number of factors. Reimbursable work by the Transmission Services increased, Power Services service contracts, agreements and grants increased and direct funding for Federal System hydro costs increased. Purchased power decreased $45 million, or eight percent, compared to the prior year. Market prices for power were considerably lower during much of Fiscal Year 2006 from levels in Fiscal Year 2005, and the physical amount of power purchases was lower over the year. Power purchases were lower due to higher hydro generation and expiring Augmentation Agreement purchases. Nonfederal projects debt service expense increased $46 million, or 16 percent, due to a variety of reasons including timing differences between Energy Northwest's fiscal year and Bonneville's fiscal year, increases in new bond issuances to fund new capital investment in the Columbia Generating Station, and increased taxable debt issued to cover issuance costs related to refinancing of Energy Northwest bonds. The portfolio includes federal appropriations, bonds issued to the United States Treasury, and nonfederal projects debt. Portfolio management causes nonfederal debt to fluctuate between years. Federal projects depreciation and amortization decreased $22 million, or 6 percent, reflecting new depreciation rates effective October 1, 2005 for transmission services and lower expense for the Corps.

Net interest expense for Fiscal Year 2006 decreased $16 million, or six percent, compared to a year earlier. Interest on appropriated funds owed the United States Treasury increased $13 million, or seven percent. Interest on bonds issued to the United States Treasury decreased $17 million, or 17 percent, as the weighted average interest rate declined from 4.9 percent at the beginning of Fiscal Year 2005 to 4.8 percent at the beginning of Fiscal Year 2006. Interest expense on bonds also decreased as the income earned on Bonneville's cash account at the United States Treasury increased $11 million with higher cash balances. (Bonneville reports this interest expense net of the interest income earned.) Interest expense decreased as allowance for funds used during construction increased $12 million, or 69 percent.

Net revenues were $611 million in Fiscal Year 2006, an increase of $124 million, or 26 percent, from Fiscal Year 2005 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the unrealized fair value of derivative instruments and nonfederal debt management actions that differ from rate case assumptions) were $445 million compared to $126 million in Fiscal Year 2005.

Statement of Non-Federal Project Debt Service Coverage

The "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" below uses the "Federal System Statement of Revenue and Expenses (unaudited)" 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 and United States Treasury Payments," 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 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,	2008	2007	2006
Total Operating Revenues	$3,036,618	$3,268,640	$ 3,419,369
Less: Operating Expense[1]	1,463,174	1,645,108	1,638,746
Net Funds Available for Non-Federal Project Debt Service	1,573,444	1,623,532	1,780,623
Less:			
Non-Federal Project Debt Service[2]	479,493	335,289	331,857
Lease Financing Program[3]	11,063	8,032	5,770
Revenue Available for Treasury	1,082,888	1,280,211	1,442,996
Amount Allocated for Payment to Treasury[8]:			
Corps and Reclamation O&M[4]	243,073	234,469	217,154
Net Interest Expense[5]	227,968	236,747	261,543
Lease Financing Program[3]	(11,063)	0	0
Capitalization Adjustment[6]	64,905	64,905	64,905
Allowance for Funds Used During Construction[5] [7]	13,596	8,165	9,605
Amortization of Principal	555,269	618,400	640,921
Total Amount Allocated for Payment to Treasury[8]	1,093,748	1,162,686	1,194,128
Revenues Available for Other Purposes[9]	(10,860)	117,525	248,868
Non-Federal Project Debt Service Coverage Ratio[10]	3.2	4.7	5.3
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[11]	1.6	1.6	1.7

(1) Operating Expenses include the following items from the Federal System Statement of Revenues and Expenses: Bonneville O & M, Purchased Power, Book-outs, 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 Reclamation. Treatment of the Corps, Reclamation and Fish and Wildlife Service operating expense is described in "—Direct Funding of Federal System Operations and Maintenance Expense."

(2) Includes debt service for generating resources acquired by Bonneville under net billing agreements or other capitalized contracts. Non-net billed debt service amounted to, $22.6 million, $23.9 million, and $32.7 million for Fiscal Years 2006, 2007 and 2008, respectively.

(3) Debt service payments, including interest, by Bonneville with respect to certain transmission facilities owned by NIFC, NIFC II and NIFC III, leased to Bonneville on a capitalized basis. To reconcile Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) the Lease Financing Program as shown here is a reduction of Revenue Available for Treasury.

(4) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Reclamation and Fish & Wildlife for Fiscal Years 2006, 2007 and 2008. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(5) Beginning with Fiscal Year 2008, Lease Financing Program is included in Net Interest Expense as reported in the audited financial statements of the Federal System. Amounts shown are calculated on an accrual basis.

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

(7) The Allowance for Funds Used During Construction is Bonneville's portion of the interest component on the Federal investment during the construction period.

(8) In contrast to the Amount Allocated for Payment to Treasury, Bonneville's payments to the United States Treasury in Fiscal Years 2006, 2007 and 2008 were $1.113 billion, $1.045 billion and $963 million, respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation and Fish & Wildlife as portrayed under "Corps and Reclamation O&M." See "—Direct Funding of Federal System Operations and Maintenance Expense."

(9) Revenues Available For Other Purposes approximates the change in reserves from year to year. Fiscal year end reserves have been as low as $188 million at the end of Fiscal Year 2002 (not depicted).

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

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

(11) The "Non-Federal Project Debt Service plus Operating Expense Coverage Ratio" is defined as follows:

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

Management Discussion of Unaudited Results for the Three Months Ended December 31, 2008

For the three months in the fiscal year-to-date ended December 31, 2008 ("Fiscal Year 2009 First Quarter"), modified net revenues were $25 million lower when compared to the comparable period a year earlier, primarily due to the decline in net revenues discussed below. Modified net revenues are net revenues after removing the effects of derivative instruments and nonfederal debt management actions that differ from rate case assumptions. Management has determined that modified net revenues are a better representation of the outcomes of normal operations during periods of debt management actions and fluctuations in derivative market prices. The primary reason for the change in modified net revenues is that Power Services sales declined $37 million, or 6 percent, because of lower power rates for Preference Customers. See "—2007-2009 Power Rate Proposal and the 2008 Supplemental Power Rate Proposal." In aggregate, Bonneville's total sales revenues decreased $31 million, or about 4 percent, when compared to the first quarter of the prior fiscal year, as the decline in Power Services revenues was in part offset by an increase in Transmission Services sales of $6 million, or 4 percent. The major reason for the Transmission Services revenue increase was increased revenue from the sale of certain services that support system reliability and the transmission of electricity ("ancillary services") of $6.3 million.

Operations and maintenance increased $3 million, or 1 percent, for Fiscal Year 2009 First Quarter when compared to the first quarter a year earlier. Purchased power decreased $10 million, or 8 percent, due to lower market prices. Nonfederal projects debt service increased $3 million, or 2 percent, primarily due to increased amortization for Energy Northwest's Columbia Generating Station nuclear plant. Interest expense increased $1 million, or 2 percent, and allowance for funds used during construction increased $2 million, or 43 percent, in each case when compared to the first quarter a year earlier. The primary reasons for these two items were increases in the lease-purchase of transmission assets and increases in customer advances for construction. Interest income increased $.4 million, or 2 percent, due to higher cash balances.

4(h)(10)(C) credits to Bonneville's United States Treasury payments for certain costs paid by Bonneville for fish and wildlife decreased $1 million, or 6 percent, because of lower market prices for purchased power. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville."

The unrealized fair value of Bonneville's derivative instruments decreased by $24 million for Fiscal Year 2009 First Quarter when compared to the comparable period a year earlier. The change was primarily the result of a $28 million decrease in the value of interest rate swap agreements due to a decrease in the LIBOR index rate. See "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

For further information regarding Fiscal Year 2009 First Quarter unaudited results, see Appendix B-2 entitled "FEDERAL SYSTEM UNAUDITED REPORT FOR THE THREE MONTHS ENDED DECEMBER 31, 2008." For information regarding Bonneville's Fiscal Year 2009 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2009 Expectations."

BONNEVILLE LITIGATION

ESA Litigation

National Wildlife Federation v. National Marine Fisheries Service, American Rivers v. Bonneville Power Administration, and Pace v. Bonneville Power Administration

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 FCRPS Biological Opinion and incidental take statement were 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, Reclamation, 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 intervened in this lawsuit. The court heard oral argument on motions for summary judgment in April 2003.

In early May 2003, the United States District Court judge issued a decision on the adequacy of the 2000 Biological Opinion. The ruling provided that the 2000 Biological Opinion was inadequate because it relied on offsite mitigation measures that were "not reasonably certain to occur" and because the biological opinion used an "action area" (the geographically delineated area comprising where the dam's operation directly or indirectly affect ESA listed species) that was too small. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court.

On November 30, 2004, NOAA Fisheries finalized a new biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies identified by the reviewing court. For a discussion of the 2004 Biological Opinion, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Columbia River System Biological Opinions." Plaintiffs filed a complaint against NOAA Fisheries and subsequently filed another complaint against the Corps and Reclamation with the District Court alleging that the 2004 Biological Opinion and the Corps' and Reclamation's decisions to operate consistent with the Biological Opinion violated certain provisions of the ESA and APA. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The ruling was finalized in October 2005, and the court remanded the matter to the Federal agencies to correct identified deficiencies. The Federal Government and the State of Idaho filed appeals. The Ninth Circuit upheld the District Court and denied the appeals. Additionally, in the court's October remand order, the Federal agencies were ordered to undertake collaboration with the sovereign parties to the litigation (states and tribes) to address key issues in a new biological opinion.

There has also been related litigation in which plaintiffs have sought injunctive relief on certain Federal System dam operations that were included in the original 2004 Biological Opinion. The court ordered additional spill to that provided in the 2004 Biological Opinion which was requested by plaintiffs and intended to aid downstream migration of juvenile salmon and steelhead species in the summer of 2005. When water is spilled, it is diverted through dam spillways and does not run through hydroelectric turbines, thereby reducing power generation. Bonneville estimated that the court-ordered spill resulted in about $75 million in foregone power revenues in Fiscal Year 2005 when compared to the revenues that would have accrued had summer spill occurred as required under the 2004 Biological Opinion.

For 2006 river operations, the Federal Government proposed (and the court approved) a spill program that was similar although not identical to the spill program the court had ordered in the summer of 2005. Bonneville estimates that the 2006 spill order, which included spring as well as summer spill, resulted in somewhat greater hydroelectric generation than would have occurred under the 2005 summer spill program. For 2007 and 2008 hydro-operations, the Federal Agencies proposed a spill program similar to the program of the previous year and obtained court approval.

The 2008 Columbia River System Biological Opinion was issued on May 5, 2008. Bonneville issued its record of decision adopting the actions in the 2008 Columbia River System Biological Opinion on August 12, 2008. A number of interests have filed litigation in connection with the 2008 Columbia River System Biological Opinion in the United States District Court for the District of Oregon against NOAA Fisheries, the Corps and Reclamation, and have included claims under the ESA as well as the Clean Water Act. In addition, some interests have filed litigation against Bonneville regarding the 2008 Columbia River System Biological Opinion in the Ninth Circuit Court, which has exclusive direct review jurisdiction review over most of Bonneville's administrative actions.

For 2009, the Federal Agencies are operating under the terms of the 2008 Columbia River System Biological Opinion, which provides for spring and summer spill similar to that provided in 2007 and 2008. A motion for preliminary injunction calling for additional spill and changes in reservoir operations has been filed by certain plaintiffs who challenged operations in 2006, 2007 and 2008. On January 9, 2009, the United States District Court for the District of Oregon suspended the briefing schedule for the motion for preliminary injunction until after March 6, 2009. If plaintiffs prevail in their motion for injunctive relief, it is possible that the court could order changes in Federal System hydro-operations to alter river flows in aid of migrating fish, which could result in significant adverse impacts on the operation of the Federal System for the generation of electricity.

See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Columbia River System Biological Opinions."

Willamette River Project

In September 2007, Willamette Riverkeepers and the Northwest Environmental Defense Center filed litigation under the ESA against the Corps, Fish and Wildlife, and NOAA Fisheries, with respect to the Willamette River Project. The litigation alleged that the federal agencies that cooperate in the management of the Willamette River Project had failed to meet their obligation under the ESA to consult with Fish and Wildlife and NOAA Fisheries to develop and implement a biological opinion for the Willamette River Project. The parties reached a stipulated settlement to stay the case until the consultation would be completed. The biological opinion was issued in July 2008, and thus far, no new suit has been initiated.

DSI Service ROD Litigation

On June 30, 2005, Bonneville issued a record of decision entitled "Bonneville Power Administration's Service to the Direct Service Industrial Customers for Fiscal Years 2007-2011" ("DSI ROD"). The DSI ROD established a policy that Bonneville will use to define service benefits that Bonneville may provide to the DSIs during Fiscal Years 2007 through 2011, among other things.

On September 28, 2005, Alcoa, Inc. ("Alcoa"), a Bonneville direct service industrial customer, filed a petition for review in the Ninth Circuit Court challenging the DSI ROD. On the same day, the Pacific Northwest Generating Cooperative ("PNGC"), a consortium of Bonneville Preference Customers, filed a separate petition for review. Alcoa's legal theory is that Bonneville has a perpetual obligation to serve the DSIs with actual, physical power at Bonneville's lowest cost-based rates. Conversely, PNGC contends that Bonneville lacks statutory authority to provide service benefits to the DSIs. In August 2006, Alcoa and PNGC filed additional petitions related to Bonneville's decisions for service to the DSIs in Fiscal Years 2007-2011. These additional petitions challenge Bonneville's Supplement to the DSI ROD, issued on May 31, 2006, and the power sales contracts executed by and between Bonneville and the aluminum company DSIs in June 2006. Additionally, on October 6, 2006, Alcoa filed a petition challenging Bonneville's execution of a power sales contract to serve Port Townsend Paper Company, a small non-aluminum DSI customer. Finally, in November 2006, the Industrial Customers of Northwest Utilities filed a petition that likewise challenges Bonneville's Port Townsend Paper Company power sales contract. All of the foregoing petitions have been consolidated, and oral arguments and briefing have been completed.

On December 17, 2008, the Ninth Circuit Court affirmed Bonneville's long-held position that Bonneville has the statutory authority, but not the obligation, to sell power to the DSIs after Fiscal Year 2001. However, the court determined that if Bonneville elects to sell firm power to the DSIs, whether pursuant to section 5(d) or 5(f) of the Northwest Power Act, Bonneville must first offer such power at the Industrial Firm Power ("IP") Rate. Only after the DSIs have refused to purchase power at the IP rate may Bonneville offer them power under Bonneville's FPS rate schedule, which is a rate schedule that Bonneville includes in its wholesale power rate proposals which rate schedule provides Bonneville substantial flexibility in pricing sales of power. (Bonneville sells much of its secondary energy at market prices under the FPS rate schedule, but sales under the FPS schedule are not limited to market price sales.) The court also agreed with Bonneville that it has the authority to monetize its DSI contracts, so long as doing so is otherwise consistent with Bonneville's statutory obligations.

The Ninth Circuit Court held that Bonneville impermissibly agreed to forgo revenue by monetizing the difference between a rate for DSIs below the rate authorized by statute (the "IP Rate") and prices available on the open market. The foregone revenue resulted in higher rates for all other customers, creating an impermissible subsidy and making it inconsistent with Bonneville's obligation to maintain the lowest possible rates consistent with sound business principles.

For Fiscal Year 2009 only, Bonneville and Alcoa have agreed to contract amendments to conform the agreement to the court's ruling. Bonneville believes that under the amendment, the monetized power benefits it provides Alcoa for the remainder of Fiscal Year 2009 will likely be the same as expected under the original agreement. The amendment assures that in no event will the monetized power benefit be greater than originally agreed to. In January 2009, PNGC, filed litigation in the Ninth Circuit Court challenging Bonneville's agreement to amend the Alcoa agreement.

Bonneville and CFAC have also executed certain contract amendments to recalculate payments for the months of December 2008, and January and February 2009, to be consistent with the court's December 2008 ruling. The amendments are substantially similar to the amendments entered into with Alcoa in January 2009, and would provide for Bonneville to monetize a power sale to CFAC in a manner consistent with the court's December 2008 ruling. CFAC agreed to certain minimum operations through June 2009 and to employ a minimum of 85 workers, or the amendments may be terminated by Bonneville. In the event CFAC were to meet the foregoing operating and employment level requirements through June, it would be eligible to receive payments from Bonneville under the amendments for operations through September 2009. Bonneville made drafts of the CFAC amendments available for public review and comment. In view of the litigation by PNGC challenging the Alcoa amendments, Bonneville expects litigation will be filed challenging the CFAC amendments.

It is uncertain at this time whether Bonneville will take retroactive action regarding payments made to Alcoa or CFAC during Fiscal Years 2007 and 2008, which payments may have exceeded the amount that would have been paid if the contract had included terms consistent with the above referenced court opinion. Bonneville will separately evaluate the actions it should take with respect to the contract for Fiscal Years 2010 and 2011. Similar evaluations and amendments will likely be required for the Port Townsend power sales contract.

In January 2009, Bonneville developed but did not enter into a long-term contract with Alcoa for Fiscal Years 2012 through 2028. It is possible that Bonneville may propose another contract with Alcoa for such period in Fiscal Year 2009. Bonneville also may enter into contracts for the same period with CFAC and Port Townsend. If Bonneville enters into long-term contracts with the DSIs, Bonneville expects to include terms that address the court's concerns as stated in the recent ruling. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Power Loads and Related Contracts and Power Rates through Fiscal Year 2011—Regional Power Sales and Related Agreements in Fiscal Years 2009 through 2011."

Long-Term Regional Dialogue Contracts, Policies and Records of Decision

On October 16, 2007, Alcoa, Inc., and the Public Power Council, a coalition of Preference Customers, each filed a petition for review under the Northwest Power Act challenging Bonneville's Long-Term Regional Dialogue Final Policy, and Bonneville's Long-Term Regional Dialogue Record of Decision ("July 2007-ROD"), both of which were issued on July 19, 2007. The Long-Term Regional Dialogue Final Policy addresses Bonneville's role in power marketing for the period after Fiscal Year 2011, and lays the foundation for Bonneville to move forward to develop power sales contracts, products, services and rates that will be established for the period of time covered by the policy. Bonneville's July 2007-ROD explains Bonneville's rationale for its determinations in the Regional Dialogue Policy. On February 18, 2009, the parties filed a joint motion to vacate the briefing schedule and stay proceedings. The parties advised the court that they will file an additional motion to consolidate these cases with a series of new petitions for review that have been filed, described immediately below

On January 27, 2009, Avista Corp., a Regional IOU, filed a petition for review in the Ninth Circuit Court challenging Bonneville's Long-Term Regional Dialogue Contract Record of Decision dated October 31, 2008 ("October 2008-ROD"). Numerous other petitions for review were filed shortly thereafter challenging the October 2008-ROD and/or certain Regional Dialogue power sale contracts that were executed on or around December 1, 2008. At this juncture, the nature of the challenges is not yet known. On February 27, 2009, Bonneville filed a motion to consolidate these cases as well as a motion to vacate the briefing schedules that were automatically established upon the filing of the petitions for review. Bonneville's motion is pending. On February 17, 2009, Clatskanie Peoples Utility District, a Preference Customer, filed a motion to expedite briefing. On February 27, 2009, Bonneville filed a response in opposition to Clatskanie's motion. Clatskanie's motion is pending. In addition, on February 20, 2009, the court issued an order stating that there will be a mediation assessment conference in these cases on March 17, 2009. It is anticipated that the court will establish a briefing schedule and a date for Bonneville to file the administrative record.

On December 17, 2008, Public Utility District No. 1 of Clark County ("Clark County") filed a petition for review in the Ninth Circuit Court challenging certain provisions of its Regional Dialogue power sales contract, executed on December 1, 2008. Clark County alleges that these provisions require Clark County to waive its statutory rights to full participation in the residential exchange and billing credits programs established under the Northwest Power Act. The briefing schedule in this case has been suspended and, on February 19, 2009, the court issued an order scheduling a mediation assessment conference for March 19, 2009. Neither Bonneville nor Clark County have moved to consolidate this case with the other cases challenging the Regional Dialogue Contract Policy Record of Decision, or Regional Dialogue power sales contracts.

Puget Sound Energy, a Regional IOU, filed a petition for review on January 27, 2009 challenging Bonneville's Tiered Rates Methodology Record of Decision ("Tiered Rates ROD") and Bonneville's Tiered Rates Methodology, both issued November 10, 2008. Numerous other petitions for review were filed shortly thereafter challenging the same Tiered Rates ROD and the methodology. The specific nature of the parties' challenges is not all known at this juncture. On February 6, 2009, one of the parties filed a motion to consolidate these cases as well as a motion to suspend the briefing schedules. Bonneville filed a response generally supporting the motion, but noting a limited objection.

2002 Final Power Rates Challenge

On May 3, 2007, the Ninth Circuit Court issued (i) an opinion with respect to petitions for review challenging Bonneville's decision in 2000 to enter into the Residential Exchange Program Settlement Agreements ("PGE Proceeding") (discussed in the immediately following section) and (ii) an opinion with respect to petitions for review challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006 (*Golden Northwest Aluminum, Inc. v. Bonneville*) (the "Golden Northwest Proceeding"). Numerous Bonneville customers filed petitions for review in the Ninth Circuit Court challenging Bonneville's power rates for the five years ended September 30, 2006. In the Golden Northwest Proceeding, the court upheld Bonneville's authority to acquire resources to replace reductions in the capability of Bonneville's Federal Base System (FBS) resources and the allocation of expanded FBS costs to Preference Customers. The court also held that Bonneville had improperly allocated costs of Bonneville's 2000 Residential Exchange Program Settlement Agreements to Preference Customers. Finally, the court held that Bonneville should have revised its forecast of fish and wildlife costs to consider whether higher fish and wildlife costs should have been assumed in developing rates. The court remanded to Bonneville to "set rates in accordance" with its opinion.

Bonneville did not file a petition for rehearing; however Regional IOUs, respondent-intervenors in the PGE Proceeding, filed petitions for rehearing and rehearing *en banc* on July 18, 2007. The court later denied the petitions for rehearing. Bonneville addressed the implications of the Ninth Circuit Court opinion in administrative proceedings, including the 2008 Supplemental Power Rate Proposal. Bonneville issued its final record of decision for that proceeding in September 2008 and filed its proposal with the Federal Energy Regulatory Commission on September 29, 2008.

Residential Exchange Program Litigation

In Fiscal Year 2000, 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 SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," "—Power Marketing in Fiscal Years 2007 through 2011—Residential Exchange Program Obligations to Preference Customers," and "—Power Marketing in Fiscal Years 2007 through 2011—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

During the same time-frame, Bonneville negotiated certain agreements (the "Residential Exchange Program Settlement Agreements") with Regional IOUs, which agreements were intended 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.

In June 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements intended to affect such Regional IOUs' Residential Exchange Settlement Agreements. Among other things, these additional agreements were intended to reduce Bonneville's obligation to sell power to meet loads of Puget and PacifiCorp and to reduce by one half certain payments in the aggregate amount of $200 million that Bonneville otherwise then owed to the two subject Regional IOUs in Fiscal Years 2005 and 2006 under the terms of their Residential Exchange Settlement Agreements.

Bonneville also entered into agreements with respect to the other four Regional IOUs. Under these agreements, Bonneville intended to obtain reductions in financial payments to such Regional IOUs of about $3-$4 million in aggregate, per year.

Beginning in 2004, 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. Among those participating in the litigation were a group of DSIs, all six Regional IOUs and a number of Preference Customers and Preference Customer groups. The litigation challenging the

Residential Exchange Settlement Agreements is referred to as the "PGE Proceeding." See "—2002 Final Power Rates Challenge." The petitions for review challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006 are referred to as the "Golden Northwest Proceeding."

Public Utility District No. 1 of Snohomish County, Washington ("Snohomish"), a large Preference Customer, filed an additional petition for review in the Ninth Circuit Court challenging Bonneville's Record of Decision, dated October 21, 2003, wherein Bonneville determined it would offer to settle multiple lawsuits in hopes of reaching a global settlement of many related lawsuits. The proceeding is referred to herein as the "Snohomish 2 Proceeding." The settlement offer was ultimately rejected. On October 11, 2007, the court issued a memorandum opinion dismissing the Snohomish 2 Proceeding for lack of jurisdiction.

On April 27, 2004, Snohomish filed a petition for review in the Ninth Circuit (the proceeding is referred to herein as the "Snohomish 3 Proceeding") related to the Snohomish 2 Proceeding. In the Snohomish 3 Proceeding, as in the Snohomish 2 Proceeding, petitioner challenged aspects of Bonneville's record of decision, dated October 21, 2003, supporting Bonneville's litigation settlement proposal, and also challenged contracts between Bonneville and certain Regional IOUs. On October 11, 2007, the court dismissed the Snohomish 3 Proceeding for lack of jurisdiction.

Public Utility District No. 1 of Grays Harbor County, Washington, challenged Bonneville's record of decision on its "Financial Settlement Agreement And Amendment To Residential Exchange Program Settlement Agreement With PacifiCorp," and Bonneville's record of decision for its "Amended Residential Exchange Program Settlement Agreement With Puget Sound Energy." On October 11, 2007, the court issued a memorandum opinion dismissing the case as moot.

On May 3, 2007, the Ninth Circuit Court issued (i) an opinion with respect to the petitions for review in the PGE Proceeding challenging Bonneville's decision in 2000 to enter into the Residential Exchange Settlement Agreements in connection with the Residential Exchange Program, and (ii) an opinion with respect to petitions for review in the Golden Northwest Proceeding challenging certain aspects of Bonneville's final power rates for Fiscal Years 2002 through 2006. The court in the PGE Proceeding held that Bonneville failed to properly implement the Residential Exchange Program provisions of the Northwest Power Act when it entered into the Residential Exchange Settlement Agreements, and that such agreements are "inconsistent with the Northwest Power Act." The court in the Golden Northwest Proceeding held, among other things, that consistent with its holding in the PGE Proceeding, Bonneville improperly allocated to Preference Customers' rates, the costs of providing Residential Exchange Program benefits to the Regional IOUs under the Residential Exchange Program Settlement Agreements. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge." The Regional IOUs filed petitions for rehearing of the ruling in the PGE Proceeding. The motions were denied.

In 2004, three parties, including Snohomish, filed petitions for review in the Ninth Circuit challenging Bonneville's Record of Decision, dated May 25, 2004, entitled "Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities Regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007-2011," ("Exchange Settlement Payment ROD") and the related contracts and amendments. On October 11, 2007, the court issued an opinion stating that it could not determine how Bonneville would treat the 2004 contract amendments in light of the ruling in the PGE Proceeding, and remanded that determination to Bonneville.

By orders dated October 11, 2007, the court remanded to Bonneville for consideration in light of the PGE Proceeding and the Golden Northwest Proceeding the 2004 amendatory agreements to the Residential Exchange Program Settlement Agreements and certain other provisions. Bonneville ceased making payments under the Residential Exchange Program Settlement Agreements and Bonneville is addressing the foregoing court rulings with regard to the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011—Changes and Proposed Changes in the Provision of Residential Exchange Program Benefits."

The court's ruling setting aside the Residential Exchange Settlement has led Bonneville to propose new rates, Residential Exchange benefit determinations, RPSAs, and related matters, and as a consequence has engendered litigation by Bonneville customers seeking to challenge such proposed rates, determinations, RPSAs, and related matters. Seven separate challenges have been filed. Bonneville believes that some or all of the challenges are likely to be dismissed as premature since FERC has not yet issued final approval of the rates and related matters. Nonetheless, Bonneville expects that any such challenges are likely to be re-filed if and when FERC approves the rates and related matters.

Southern California Edison v. Bonneville Power Administration

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

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

Conversion from Sale to Exchange Mode ("Conversion Claim"). 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 sought damages in the amount of approximately $186,000,000.

Challenge to FPS-96R ("Rate Adjustment Claim"). On December 30, 2003, SCE filed a complaint in the Court of Federal Claims seeking damages in the amount of $32,000,000.

Termination for Default ("Termination Claim"). 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 a complaint in November 2004 seeking $22,000,000 in termination for convenience damages.

On June 5, 2006, Bonneville and SCE executed an agreement to settle the Conversion Claim and the Termination Claim, whereby Bonneville will make a settlement payment of $28.5 million plus interest to SCE in exchange for SCE's dismissing the two claims. The settlement agreement identifies two conditions precedent to final resolution: (i) SCE must obtain approval of the settlement from the California Public Utilities Commission ("CPUC"); and, (ii) Bonneville must complete a public review and comment process, and subsequently reaffirm the settlement. Payment by Bonneville is due when it receives a final resolution of its refund liability, if any, in the California refund proceedings. (The California refund proceedings are described in "POWER SERVICES—Customers and Other Power Contract Parties of Bonneville's Power Services—Effect on Bonneville of Developments in California Power Markets in 1999-2001.") SCE filed the proposed settlement with the CPUC and it has approved the settlement. Bonneville has completed its public review process, and reaffirmed the proposed settlement on August 2, 2006. As such, Bonneville accrued a liability of $28.5 million during Fiscal Year 2006. However, payment has yet to be made pending resolution of the California refund proceedings and any related litigation. Once final resolution of Bonneville's refund liability, if any, has been determined, Bonneville will pay SCE $28.5 million plus interest.

In addition, in 2007, the parties reached an agreement to settle the Rate Adjustment Claim. In October 2007, Bonneville made a payment of $13.4 million plus interest to SCE in exchange for SCE's dismissing the claim.

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. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Marketing in Fiscal Years 2007 through 2011," "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Service Rates" and "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—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, while meeting other existing requirements applicable to Bonneville's transmission rates. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Miscellaneous Litigation

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

REPORT OF INDEPENDENT AUDITORS

PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying combined balance sheets and the related combined statements of revenues and expenses, of changes in capitalization and long-term liabilities and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2008, and 2007, and the results of its operations and its cash flows for each of the three years ended September 30, 2008, and the changes in its capitalization and long-term liabilities for each of the two years ended September 30, 2008, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Portland, Oregon
October 30, 2008

COMBINED BALANCE SHEETS

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

ASSETS

	2008	2007
Federal utility plant		
Completed plant	**$ 13,480,633**	$ 13,278,856
Accumulated depreciation	**(4,933,348)**	(4,825,295)
	8,547,285	8,453,561
Construction work in progress	**890,883**	851,620
Net federal utility plant	**9,438,168**	9,305,181
Nonfederal generation	**2,492,645**	2,465,230
Current assets		
Cash	**1,731,238**	1,475,544
Accounts receivable, net of allowance	**112,129**	140,335
Accrued unbilled revenues	**203,011**	181,526
Materials and supplies, at average cost	**75,719**	68,334
Prepaid expenses	**21,682**	19,938
Total current assets	**2,143,779**	1,885,677
Other assets		
Regulatory assets	**5,447,404**	5,938,724
Nonfederal nuclear decommissioning trusts	**157,743**	162,438
Deferred charges and other	**176,045**	206,398
Total other assets	**5,781,192**	6,307,560
Total assets	**$19,855,784**	**$19,963,648**

The accompanying notes are an integral part of these statements.

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CAPITALIZATION AND LIABILITIES

	2008	2007
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,664,460**	$ 2,402,565
Federal appropriations	**4,247,972**	4,326,688
Borrowings from U.S. Treasury	**1,745,500**	1,760,900
Nonfederal debt	**6,182,403**	6,262,295
Total capitalization and long-term liabilities	**14,840,335**	14,752,448
Commitments and contingencies (Note 10)		
Current liabilities		
Federal appropriations	**9,889**	10,913
Borrowings from U.S. Treasury	**440,400**	479,600
Nonfederal debt	**284,469**	288,758
Accounts payable and other	**588,275**	346,352
Total current liabilities	**1,323,033**	1,125,623
Other liabilities		
Regulatory liabilities	**2,665,517**	2,050,228
IOU exchange benefits	**69,600**	1,068,217
Asset retirement obligations	**159,800**	175,500
Deferred credits	**797,499**	791,632
Total other liabilities	**3,692,416**	4,085,577
Total capitalization and liabilities	**$19,855,784**	**$19,963,648**

The accompanying notes are an integral part of these statements.

COMBINED STATEMENTS OF REVENUES AND EXPENSES

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

	2008	2007	2006
Operating revenues			
Sales	**$2,897,347**	$ 3,136,216	$ 3,370,432
Derivative instruments	**(30,564)**	(6,519)	(100,093)
U.S. Treasury credits for fish	**100,392**	66,097	76,353
Miscellaneous revenues	**69,443**	72,846	72,677
Total operating revenues	**3,036,618**	3,268,640	3,419,369
Operating expenses			
Operations and maintenance	**1,256,213**	1,569,504	1,320,880
Purchased power	**450,035**	310,073	535,020
Nonfederal projects	**479,493**	343,321	337,627
Depreciation and amortization	**358,064**	351,787	353,236
Total operating expenses	**2,543,805**	2,574,685	2,546,763
Net operating revenues	**492,813**	693,955	872,606
Interest expense and (income)			
Interest expense	**340,658**	344,379	340,586
Allowance for funds used during construction	**(32,057)**	(33,172)	(28,514)
Interest income	**(80,633)**	(74,460)	(50,529)
Net interest expense	**227,968**	236,747	261,543
Net revenues	**264,845**	457,208	611,063
Accumulated net revenues at Oct. 1	**2,402,565**	1,945,357	1,334,294
Irrigation assistance	**(2,950)**	—	—
Accumulated net revenues at Sept. 30	**$2,664,460**	**$2,402,565**	**$1,945,357**

The accompanying notes are an integral part of these statements.

COMBINED STATEMENTS OF CHANGES IN CAPITALIZATION AND LONG-TERM LIABILITIES

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

	Accumulated Net Revenues	Federal Appropriations	Borrowings from U.S. Treasury	Nonfederal Debt	Total
Balance at Sept. 30, 2006	**$1,945,357**	**$4,323,729**	**$2,481,800**	**$6,515,258**	**$15,266,144**
Federal construction appropriations:					
Increase	—	125,972	—	—	125,972
Repayment	—	(112,100)	—	—	(112,100)
Borrowings from U.S. Treasury:					
Increase	—	—	315,000	—	315,000
Repayment	—	—	(506,300)	—	(506,300)
Refinanced	—	—	(50,000)	—	(50,000)
Nonfederal debt:					
Increase	—	—	—	66,148	66,148
Repayment	—	—	—	(30,353)	(30,353)
Net revenues	457,208	—	—	—	457,208
Balance at Sept. 30, 2007	**$ 2,402,565**	**$ 4,337,601**	**$2,240,500**	**$ 6,551,053**	**$ 15,531,719**
Federal construction appropriations:					
Increase	**—**	**70,929**	**—**	**—**	**70,929**
Repayment	**—**	**(150,669)**	**—**	**—**	**(150,669)**
Borrowings from U.S. Treasury:					
Increase	**—**	**—**	**425,000**	**—**	**425,000**
Repayment	**—**	**—**	**(404,600)**	**—**	**(404,600)**
Refinanced	**—**	**—**	**(75,000)**	**—**	**(75,000)**
Nonfederal debt:					
Increase	**—**	**—**	**—**	**58,242**	**58,242**
Repayment	**—**	**—**	**—**	**(142,423)**	**(142,423)**
Net revenues	**264,845**	**—**	**—**	**—**	**264,845**
Irrigation assistance	**(2,950)**	**—**	**—**	**—**	**(2,950)**
Balance at Sept. 30, 2008	**$ 2,664,460**	**$ 4,257,861**	**$2,185,900**	**$ 6,466,872**	**$ 15,575,093**

The accompanying notes are an integral part of these statements.

COMBINED STATEMENTS OF CASH FLOWS

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

	2008	2007	2006
Cash provided by operating activities			
Net revenues	**$ 264,845**	$ 457,208	$ 611,063
Non-cash items:			
Depreciation and amortization	**358,064**	351,787	353,236
Amortization:			
Terminated facilities and sponsored conservation	**131,393**	21,373	11,672
Capitalization adjustment	**(64,905)**	(64,905)	(64,905)
Changes in:			
Receivables and unbilled revenues	**6,721**	62,736	(87,612)
Materials and supplies	**(7,385)**	3,431	3,308
Prepaid expenses	**(1,744)**	1,515	299,579
Accounts payable and other	**185,839**	39,140	186,751
Cash provided by operating activities	**872,828**	872,285	1,313,092
Cash provided by and (used) for investment activities			
Investment in:			
Federal utility plant (including AFUDC)	**(412,055)**	(435,758)	(402,474)
Nonfederal projects	**(27,415)**	(30,165)	(45,620)
Transfer from Spectrum Relocation Fund	**—**	48,627	—
Nonfederal nuclear decommissioning trusts	**(7,300)**	(6,691)	—
Special purpose corporation's trust funds:			
Deposits to	**(74,474)**	(51,070)	—
Receipts from	**65,779**	5,955	—
Cash used for investment activities	**(455,465)**	(469,102)	(448,094)
Cash provided by and (used for) financing activities			
Federal construction appropriations:			
Increase	**70,929**	125,972	83,351
Repayment	**(150,669)**	(112,100)	(101,223)
Borrowings from U.S. Treasury:			
Increase	**425,000**	315,000	270,000
Repayment	**(404,600)**	(506,300)	(545,000)
Refinanced	**(75,000)**	(50,000)	(20,000)
Nonfederal debt:			
Increase	**58,242**	66,148	36,581
Repayment	**(142,423)**	(30,353)	(15,372)
Customers:			
Advances for construction	**70,356**	44,434	—
Billing credits	**(10,554)**	(5,515)	—
Irrigation assistance	**(2,950)**	—	—
Cash used for financing activities	**(161,669)**	(152,714)	(291,663)
Increase in cash	**255,694**	250,469	573,335
Beginning cash balance	**1,475,544**	1,225,075	651,740
Ending cash balance	**$ 1,731,238**	**$1,475,544**	**$1,225,075**
Cash paid for interest, net of U.S. Treasury credits	**$ 160,586**	**$ 243,010**	**$ 256,787**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ACCOUNTING PRINCIPLES

Combination and Consolidation of Entities

The Federal Columbia River Power System (FCRPS) financial statements combine the accounts of the Bonneville Power Administration (BPA), the accounts of the Pacific Northwest generating facilities of the U. S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) as well as the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan facilities. Consolidated with BPA are "Special Purpose Corporations" known as Northwest Infrastructure Financing Corporations (NIFCs), from which BPA leases certain transmission facilities (See Note 8, Nonfederal Debt).

BPA is the power marketing administration that purchases, transmits and markets power for the FCRPS. Each of the combined entities is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. While the costs of Corps and Reclamation projects serve multiple purposes, only the power portion of total project costs are assigned to the FCRPS through a cost-allocation process. All inter-company accounts and transactions have been eliminated from the combined financial statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles of the United States of America 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 component of the U.S. Department of Energy; Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior; and the Corps is part of the U.S. Department of Defense. U.S. government properties and income are tax-exempt.

Use of Estimates

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

Rates and Regulatory Authority

BPA establishes separate power and transmission rates 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 (Northwest Power Act), 16 U.S.C. 839, and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. 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 (Ninth Circuit Court). Action seeking such review must be filed within 90 days of the final FERC decision. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA.

In connection with the rate setting process, certain costs or credits may be included in rates for recovery over a future period and are recorded as regulatory assets or liabilities in accordance with generally accepted accounting principles, specifically Statement of Financial

Accounting Standards 71, "Accounting for the Effects of Certain Types of Regulation" (See Note 3, Effects of Regulation). Regulatory assets or liabilities are amortized over the periods they are included in rates. Costs are recovered through rates during the periods when the costs are scheduled to be repaid. Amortization is computed using either the straight-line method or is based upon specific amounts included in rates each year. When the straight-line method is used, it is based upon either the estimated service lives or the periods the costs are included in rates. BPA does not earn a rate of return on its regulatory assets.

Federal Utility Plant

Federal utility plant is stated at original cost and primarily includes both transmission and generation assets. Transmission assets were $6.2 billion and $6.1 billion, and generation assets were $7.3 billion and $7.2 billion at Sept. 30, 2008, and 2007, respectively. The costs of additions, major replacements and substantial betterments are capitalized. 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. Maintenance, repairs and replacements of items determined to be less than major units of property are charged to maintenance and operating expense as incurred. The cost of retiring federal utility plant units less any salvage proceeds is charged to accumulated depreciation when it is removed from service.

Depreciation

Depreciation of original cost and estimated cost to retire federal utility plant (i.e., net cost of removal) 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. The net cost of removal (the difference between cost of removal and salvage) is included in depreciation rates; however, in the event there is negative salvage (the cost of removal exceeds salvage), a reclassification of non-asset retirement obligations' negative salvage reserves is made from accumulated depreciation to a regulatory liability.

Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the estimated cost of interest on financing the construction of new assets. AFUDC is based on the construction work in progress balance and is charged to the capitalized cost of the utility plant asset. AFUDC is a noncash reduction of interest expense.

FCRPS capitalizes AFUDC at one rate for Corps and Reclamation construction funded by congressional appropriations and at another rate for construction funded substantially by BPA. AFUDC rates for appropriated funds are stipulated in the congressional acts authorizing the construction, whereas the BPA rate approximates the cost of borrowing from the U. S. Treasury. The respective rates were approximately 4.3 percent and 5.4 percent in fiscal year 2008, 5.1 percent and 5.1 percent in fiscal year 2007, and 3.9 percent and 4.8 percent in fiscal year 2006.

Nonfederal Generation

BPA has acquired all of the generating capability of Energy Northwest's Columbia Generating Station nuclear power plant. The contract to acquire the generating capability of the project requires BPA to pay all or part of the annual project budget, including operating expense and debt service. BPA also has acquired all of the output of the Cowlitz Falls hydro project and pays all operating expense and debt service. BPA recognizes expenses for these projects based upon total project cash funding requirements. The nonfederal generation assets in the Combined Balance Sheets are amortized as the principal on the outstanding bonds is repaid by the nonfederal entities (See Note 8, Nonfederal Debt).

Cash

For purposes of reporting cash flows, amounts include cash in the Bonneville Fund and unexpended appropriations of the Corps and Reclamation.

Financial Instruments

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 in order to finance its capital programs, which include Corps and Reclamation direct-funded capital investments. Of the $4.45 billion, $1.25 billion is reserved for conservation and renewable resource loans and grants.

The carrying value reflected in the Combined Balance Sheets approximates fair value for the FCRPS' financial assets and current liabilities. The fair value of borrowings from the U.S. Treasury as well as bonds issued for nonfederal debt are described in Notes 7 and 8 for Borrowings from U.S. Treasury and Nonfederal Debt, respectively.

Concentrations of Credit Risks

General Credit Risk

Financial instruments that potentially subject the FCRPS to concentrations of credit risk consist primarily of BPA accounts receivable. Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted.

BPA's accounts receivable are spread across a diverse group of public utilities, investor-owned utilities, power marketers and others that are located throughout the Western United States and Canada. The accounts receivable exposure results from BPA providing a wide variety of power products and transmission services. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. During fiscal years 2008, 2007 and 2006, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. In order to further manage credit risk, BPA obtains credit support, such as letters of credit and third-party guarantees from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Allowance for Doubtful Accounts

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific accounts, based upon the best available facts and circumstances, of customers that may be unable to meet their financial obligations, and a reserve for all other customers based on historical experience.

The largest risk relates to the California power markets that were in turmoil during 2000 to 2001 when they experienced historically high power prices and volatility, along with continued uncertainty related to deregulation. The California Independent System Operator and California Power Exchange were customers with whom BPA had contracts for power and transmission delivery during that period and they have been unable to fully pay BPA for their purchases. BPA has recorded an allowance for doubtful accounts, which in management's best estimate is sufficient to cover potential exposure. Net exposure after the allowance is not significant. BPA has continued to pursue collection of amounts due.

Post-Retirement Benefits

Federal employees associated with the operation of the FCRPS are participants in either the Civil Service Retirement System (CSRS) or the Federal Employees Retirement System (FERS). Both federal employers and their employees contribute a percentage of eligible employee compensation toward funding these post-retirement benefit plans. Based on the statutory agency contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 11.2 percent of eligible employee compensation. For fiscal year 2008, the FERS plan is considered fully funded because the combined contributions are equal to the cost to the federal government to provide the benefits. However, for CSRS the legislatively mandated contribution levels do not fully cover the cost to the federal government to provide the plan benefits. Therefore, the program is considered underfunded (See Note 10, Commitments and Contingencies). Employees also may participate in the Federal Employees Health Benefits Program and/or the Federal Employees' Group Life Insurance Program, which are similarly underfunded. Retirement benefits under the federal retirement systems are payable by the U.S. Treasury.

Derivative Instruments

BPA follows the provisions of Statement of Financial Accounting Standards (SFAS) 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 133 requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and also requires that a change 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. Purchases and sales of forward electricity contracts that require physical delivery, are expected to be used or sold by BPA in the normal course of business, and meet the definition of capacity described in SFAS 149, are generally considered normal purchases and normal sales under SFAS 133. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power costs in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

For all other derivative transactions, BPA applies fair value accounting and records the changes in fair value in the current period in the Combined Statements of Revenues and Expenses. When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. BPA does not apply hedge accounting.

BPA recorded a fair value unrealized loss in the Combined Statements of Revenues and Expenses related to its derivative portfolio (including physical power purchase and sale transactions, power exchange transactions, and interest rate swap transactions) of $(30.6) million, $(6.5) million and $(100.1) million for fiscal years 2008, 2007 and 2006, respectively.

Interest Rate Swap Transactions

BPA has entered into two floating-to-fixed LIBOR interest rate swaps to help manage interest rate risk related to its long-term debt portfolio. In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for 10 years and receives a variable rate that changes weekly tied to LIBOR. This swap transaction terminates in 2013. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for 15 years and receives a variable rate that changes weekly tied to LIBOR. This swap transaction terminates in 2018.

The floating interest rates on the swaps are reset on a weekly basis. The net effect of the two swap transactions essentially replaces variable rate debt with 3.3 percent fixed rate debt. The swap transactions do not qualify for hedge accounting treatment under SFAS 133. BPA recorded a $(17.2) million unrealized fair value loss, a $(2.2) million unrealized fair value loss, and an $8.4 million unrealized fair value gain in the Combined Statements of Revenues and Expenses for fiscal years 2008, 2007 and 2006, respectively, related to the interest rate swap transactions.

Revenues and Net Revenues

Operating revenues are recorded when services are rendered and include estimated unbilled revenues of $203 million, $182 million and $247 million at Sept. 30, 2008, 2007 and 2006, respectively.

Because BPA is a federal government power marketing administration, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS, the payment of certain irrigation costs (See Note 10, Commitments and Contingencies) and the payment of operational obligations, including debt for both operating and nonoperating nonfederal projects.

Interest Income

Interest income on the Bonneville Fund balances can be applied only as offset interest credits on payments to the U.S. Treasury. Offset interest credits are a noncash reduction of interest expense. Therefore, interest income is not included in the cash paid for interest reported in the Combined Statements of Cash Flows.

U.S. Treasury Credits for Fish

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 obligates the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes on a reimbursement basis. The Northwest Power Act also specifies 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 Northwest Power Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects. As such, BPA reduces its cash payments to the U.S. Treasury by an amount equal to the mitigation measures funded on behalf of the nonpower purposes.

Residential Exchange Program

In order to provide regional utilities, primarily investor-owned utilities, access to benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of the Northwest Power Act. Whenever a Pacific Northwest electric utility offers to sell power to BPA at the utility's average system cost of resources (ASC), BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA's PF Exchange rate to the utility for resale to that utility's residential and small farm consumers.

In May 2007, the Ninth Circuit Court rulings found the 2000 Residential Exchange Settlement Agreements with investor-owned utilities inconsistent with the Northwest Power Act. In response to the Ninth Circuit Court's rulings, BPA conducted a new wholesale power rate case that supplemented the initial fiscal year 2007 rate case. The 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case) Final Record of Decision (Final ROD) was issued on Sept. 22, 2008. The Final ROD established a "Lookback Amount" representing BPA's overpayments to investor-owned utilities from prior years, which was also the amount over-collected from preference customers (consumer-owned utilities). Preference customers are public utilities, cooperatives or public bodies, such as municipalities and public utility districts, that by law have priority access to federally generated power.

REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing rates and are collected in rates with program costs recognized when incurred net of the purchase and sale of power under the REP. Based upon the WP-07 Supplemental Rate Case, a regulatory asset and liability were recorded representing the Lookback Amount that will be collected from IOUs and returned to the consumer-owned utilities over time. In each succeeding rate case, the BPA administrator will designate the amount to be recovered from the IOUs and returned to each qualifying consumer-owned utility. These amounts will not reduce rates, but will be credits to qualifying consumer-owned utilities' bills as designated in the corresponding Final RODs. BPA recognizes a refund and reduces expense in the year it is applied, until the Lookback Amount is eliminated. These transactions are net operating revenue neutral as the same amount reduces both revenue and expense (See Note 4, Residential Exchange Program).

RECENT ACCOUNTING PRONOUNCEMENTS

BPA recognizes accounting pronouncements that may impact the financial statements and accompanying Notes. In September 2006, the

Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) 157, “Fair Value Measurements.” SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. In addition, SFAS 157 establishes a hierarchy of fair value assumptions that distinguishes between independent market participant assumptions and the reporting entity’s own assumptions about market participant assumptions.

BPA will adopt SFAS 157 for its financial assets and liabilities that are measured and either recorded or disclosed under fair value in fiscal year 2009. In February 2008, the FASB issued FASB Staff Position FAS 157-2, “Effective Dates of FASB Statement No. 157,” (FSP FAS 157-2), which defers the effective date of SFAS 157 for all nonrecurring fair value measurements of non-financial assets and liabilities for one year. BPA is evaluating the effect of adoption and implementation of SFAS 157, which is not expected to have a material impact on BPA’s financial condition, results of operations or cash flows.

In February 2007, the FASB issued SFAS 159, “The Fair Value Option for Financial Assets and Financial Liabilities.” This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. The provisions of SFAS 159, if elected, are effective for BPA in fiscal year 2009. BPA is evaluating the effect of the adoption and implementation of SFAS 159, which is not expected to have a material impact on its financial condition, results of operations or cash flows.

In March 2008, the FASB issued SFAS 161, “Disclosures about Derivative Instruments and Hedging Activities—an amendment of SFAS 133.” SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable financial statement readers to better understand how and why an entity uses derivative instruments and their effects on an entity’s financial position, financial condition and cash flows. The provisions of SFAS 161 are effective for BPA in fiscal year 2009. BPA is evaluating the impact of adopting SFAS 161.

2. ASSET RETIREMENT OBLIGATIONS

As of Sept. 30 — thousands of dollars

	2008	2007
Beginning Balance	**$ 175,500**	$ 169,300
Activities:		
Accretion	**7,200**	7,900
Expenditures	**(2,600)**	(1,800)
Revisions	**(20,300)**	100
Ending Balance	**$ 159,800**	**$175,500**

FCRPS recognizes asset retirement obligations (ARO) according to the estimated fair value of the dismantlement and restoration costs associated with the retirement of tangible long-lived assets. The liability is adjusted for any revisions, expenditures and the passage of time. FCRPS also has certain tangible long-lived assets such as federal hydro projects without an associated ARO.

AROs include the following items as of Sept. 30, 2008:

- CGS decommissioning and site restoration of $114.4 million;
- Trojan decommissioning of $27.5 million;
- Project Nos. 1 and 4 site restoration of $14.5 million;
- BPA PCBs, asbestos and wood poles of $3.4 million.

In fiscal year 2008, BPA reduced the Trojan decommissioning ARO liability by $19.9 million to reflect changes in the settlement of demolition activities, reduction in the estimated annual cash flows related to spent fuel operations and adjustments for other decommissioning activities.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

BPA also recognizes an asset that represents trust fund balances for decommissioning and site restoration costs. Decommissioning costs for CGS are charged to operations over the operating life of the project. An external trust fund for decommissioning costs is funded monthly for CGS. The trust funds are expected to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this period be no longer than 60 years from the time the plant stops operating. The plant is licensed to operate until the current operating license termination year of 2024. Trust fund requirements for CGS are based on an NRC decommissioning cost estimate and the license termination date.

BPA has funded $157.7 million and $162.4 million for the Energy Northwest AROs, which is held in trusts and recorded in other assets on the Combined Balance Sheets at Sept. 30, 2008, and 2007, respectively. The trust fund balances are $120.0 million and $37.7 million for decommissioning and site restoration, respectively at Sept. 30, 2008. Payments to the trusts for fiscal years 2008, 2007 and 2006 were approximately $7.3 million, $6.7 million and $6.2 million, respectively. The funds are invested in cash equivalents, equity and fixed income funds. The cash equivalents are valued at cost and fixed income funds and the equity funds are valued at market.

BPA directly funds Eugene Water and Electric Board's 30 percent share of Trojan's decommissioning costs through current rates. Decommissioning costs are included in operations and maintenance expense in the accompanying Combined Statements of Revenues and Expenses.

3. EFFECTS OF REGULATION

As of Sept. 30 — thousands of dollars

	2008	2007
Regulatory Assets:		
Terminated nuclear facilities	**$ 3,674,815**	$3,856,265
REP Lookback Amount from IOUs	**679,012**	—
Columbia River Fish Mitigation	**370,332**	366,969
Conservation measures	**191,300**	228,213
Direct-service industries' benefits	**173,207**	226,464
Fish and wildlife measures	**153,618**	148,514
Settlements	**46,533**	47,032
Federal Employees' Compensation Act	**34,478**	37,241
Sponsored conservation	**29,555**	33,276
Spacer damper replacement program	**28,677**	19,200
Trojan decommissioning and site restoration	**27,544**	49,196
Terminated hydro facilities	**24,725**	25,625
Capital bond premiums	**13,608**	15,498
IOU REP benefits	**—**	885,231
Total Regulatory Assets	**$ 5,447,404**	**$5,938,724**

Regulatory assets include the following items:

- "Terminated nuclear facilities" include the nonfederal debt for Energy Northwest Nuclear Project Nos. 1 and 3 and 30 percent of the Trojan project. These assets are amortized as the principal on the outstanding bonds is repaid (See Note 8, Nonfederal Debt).
- "REP Lookback Amount from IOUs" is the amount recoverable from IOUs in future rate cases that reduces their benefit payments (See Note 4, Residential Exchange Program).
- "Columbia River Fish Mitigation" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. These costs will be recovered through future rates and amortized as scheduled over 75 years.
- "Conservation measures" consist of the costs of capitalized conservation measures and are amortized over periods from five to 20 years.
- "Direct-service industries' benefits" will be recovered in rates during the periods in which the costs will be paid in fiscal years 2009 through 2011.
- "Fish and wildlife measures" consist of the capitalized fish and wildlife projects and are amortized over a period of 15 years.
- "Settlements" reflect costs related to contractual settlement agreements or proposed settlements stemming from litigation where BPA will recover costs over the life of the contracts.
- "Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.
- "Sponsored conservation" relates to the nonfederal debt for Emerald People's Utility District loans, Conservation and Renewable Energy System and City of Tacoma Conservation bonds. These were issued to finance conservation programs sponsored by BPA. The assets are amortized as the principal on the outstanding bonds is repaid.
- "Spacer damper replacement program" consists of costs to replace deteriorated spacer dampers that have been deferred and are being recovered in rates under the Spacer Replacement Program. These costs are being amortized over a period of 30 years.
- "Trojan decommissioning and site restoration" costs reflect the amount to be recovered in future rates for funding the Trojan ARO liability (See Note 2, Asset Retirement Obligations).
- "Terminated hydro facilities" include the nonfederal debt for the terminated Northern Wasco hydro project. These assets are amortized as the principal on the outstanding bonds is repaid.
- "Capital bond premiums" are the deferred losses related to refinanced debt and are amortized over the life of the new debt instruments.
- "IOU REP benefits" is the cost of the Residential Exchange Program Settlement Agreements that in fiscal year 2007 the Ninth Circuit Court found inconsistent with the Northwest Power Act (See Note 9, Other Liabilities).

As of Sept. 30 — thousands of dollars

	2008	2007
Regulatory Liabilities:		
Capitalization adjustment	**$ 1,796,511**	$ 1,861,416
REP Lookback Amount to COUs	**679,012**	—
Accumulated plant removal costs	**157,492**	140,248
CGS decommissioning and sites restoration	**28,877**	39,821
Other	**3,625**	8,743
Total Regulatory Liabilities	**$ 2,665,517**	**$ 2,050,228**

Regulatory liabilities include the following items:

- "Capitalization adjustment" is the difference between appropriated debt before and after refinancing per the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (Refinancing Act), 16 U.S.C. 838(l). The 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 $64.9 million for fiscal years 2008, 2007 and 2006, respectively.
- "REP Lookback Amount to COUs" is the amount previously collected through rates that is owed qualifying consumer-owned utilities and will be credits on their future bills (See Note 4, Residential Exchange Program).
- "Accumulated plant removal costs" is the amount previously collected through rates as part of depreciation. These costs will be amortized as actual removal costs are paid.
- "CGS decommissioning and sites restoration" is the amount previously collected through rates in excess of the ARO balances for Energy Northwest Columbia Generating Station decommissioning and site restoration as well as Project Nos. 1 and 4 sites.
- "Other" is the amount collected through billing settlements, which reduces future rates.

4. RESIDENTIAL EXCHANGE PROGRAM

As provided in the Northwest Power Act, beginning in 1981 BPA entered into 20-year Residential Purchase and Sale Agreements (RPSA) with eligible regional utility customers. The RPSAs implemented the Residential Exchange Program. In 2000, BPA signed Residential Exchange Program Settlement Agreements ("REP settlements" or "settlement agreements") with the region's six investor-owned utilities under which BPA was to provide monetary and power benefits as a settlement of residential exchange disputes for the period July 1, 2001, through Sept. 30, 2011. BPA later signed additional agreements and amendments related to the settlement agreements with IOU customers. One such agreement provided for the elimination or deferral of certain IOU benefit payments, while later agreements and amendments provided for minimum and maximum amounts for the IOUs' monetary benefits for fiscal years 2007 through 2011, provided that BPA would have no obligation to provide power to the IOUs in this period. BPA performed an analysis of the REP settlements and potential accounting implications associated with the settlement agreements. Based on this analysis BPA recorded a REP settlement agreement liability and regulatory asset for amounts recoverable in future rates (See Note 3, Effects of Regulation).

In May 2007, the Ninth Circuit Court ruled that the REP settlement agreements were inconsistent with the Northwest Power Act and that BPA improperly allocated settlement costs to BPA's preference rates. Upon notification of the rulings, BPA suspended settlement agreement payments to the IOUs. As of the end of fiscal year 2007, the account balances for the liability and regulatory asset were $1.1 billion and $885.2 million, respectively. The difference between the liability and regulatory asset was primarily attributable to the recording of the expense (asset reduction) although payments were suspended in May 2007. Rates, however, continued to be charged based on the settlement agreement amounts in the revenue requirement. As a result of the rulings, in fiscal year 2008 the associated liability and regulatory asset for the settlement agreements were reduced to zero.

In response to the Ninth Circuit Court May 2007 rulings, BPA held the WP-07 Supplemental Rate Case. On Sept. 22, 2008, the BPA administrator issued a Final ROD that revised power rates for fiscal year 2009, determined the amount the consumer-owned utilities were overcharged in prior years, determined the forecast REP benefits for the IOUs in fiscal year 2009, and determined the amount of prior overcharges that will be returned to the consumer-owned utilities in fiscal year 2009, which will be deducted from the amount of REP benefits the IOUs would otherwise receive in that year. The prior overcharges, which amount to $746.2 million for fiscal years 2002 through 2006, are labeled the "Lookback Amount" in the Final ROD.

The Lookback Amount represents amounts over-collected from consumer-owned utilities in prior years' rates, which also represents the amounts overpaid to the IOUs under the settlement agreements in prior years. In 2008 BPA recorded $679.0 million as both a regulatory liability and regulatory asset as of Sept. 30, 2008, which reflects this Lookback Amount less the $67.2 million effect of the Lookback applied in 2008 as scheduled in the Final ROD. The regulatory liability represents the amounts owed to the consumer-owned utilities that will be returned to them in future years as determined through the rate setting processes. The regulatory asset represents the amounts owed by the IOUs that will be recovered from the IOUs through future rate setting processes as reductions in REP benefits paid in future rate periods.

As described in Note 9, in 2008 BPA also adjusted liabilities related to the REP program to reflect the net obligations resulting from REP collections in rates, and REP benefits and interim payments made in fiscal years 2007 and 2008. Additionally as a result of the Ninth Circuit Court rulings and the WP-07 Supplemental Rate Case, the liability and related regulatory asset associated with the REP settlement agreement obligations that were recorded in prior years were reduced to zero in 2008.

In addition to balance sheet effects, the WP-07 Supplemental Rate Case addressed the REP settlement agreement effects for fiscal years 2007 and 2008 with regard to resolution of amounts over-collected in rates from consumer-owned utilities and paid to the IOUs. As a result, for fiscal year 2008 BPA first recognized a reduction to Sales of $340.5 million for the amount of the repayment due to the consumer-owned utilities for amounts over-collected in rates for fiscal years 2007 and 2008, as well as an amount to reduce the Lookback Amount. The Final ROD established amounts to be returned to consumer-owned utilities as computed based upon what had been charged consumer-owned utilities for IOU REP benefits in fiscal years 2007 and 2008 as compared with the revised IOU REP benefits for the same period. The $340.5 million represents the $256.8 million refund of amounts to be returned to customers over-collected in fiscal years 2007 and 2008, plus the effects of the $67.2 million Lookback Amount applied in fiscal year 2008, and $16.5 million collected in rates in 2003 for IOU benefits deferred. This adjustment had no net impact to net operating revenues as operations and maintenance expenses were also reduced by $340.5 million.

As described in the WP-07 Supplemental Rate Case, the BPA administrator will designate the amount to be recovered from the IOUs and returned to each qualifying consumer-owned utility. These amounts will not reduce rates, but will be credits to qualifying consumer-owned utilities as designated in the corresponding Final RODs. BPA will recognize the refund and reduced expense in the year it is applied, until the Lookback Amount is eliminated. These transactions are net revenue neutral as the same amount reduces both revenue and expense.

The Final ROD issued on Sept. 22, 2008, is pending interim approval from FERC which is expected in the next month. Once interim approval for fiscal year 2009 has been received, BPA has the authority to put into effect the new rates, the revised REP benefit and to apply the Lookback Amount. Once FERC grants final approval of the rates, there is a 90-day statutory window where the rates and issues related to the REP and Lookback Amount could be challenged in the Ninth Circuit Court.

5. DEFERRED CHARGES AND OTHER

As of Sept. 30 — thousands of dollars

	2008	2007
Special purpose corporations' trust funds	**$ 72,482**	$ 64,907
Derivative instruments	**40,963**	50,443
Spectrum Relocation fund	**39,243**	47,241
Energy receivable	**11,687**	18,314
Other	**11,670**	25,493
	$176,045	**$206,398**

Deferred charges and other include the following items:

- "Special purpose corporations' trust funds" are amounts held in separate trust accounts for the construction of transmission assets (See Note 8, Nonfederal Debt).
- "Derivative instruments" represents unrealized fair value gains from the derivative portfolio which includes physical power purchase and sale transactions, power exchange transactions, interest rate swap transactions, and power and heat rate option contracts.
- The Commercial Spectrum Enhancement Act created the "Spectrum Relocation fund" to reimburse the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to federal agencies. Amounts received from the U.S. Treasury in connection with the Act are restricted for use in constructing replacement assets.
- "Energy receivable" is energy to be returned to BPA for prior transmission line losses and over delivery.
- "Other" is primarily Corps and Reclamation costs for generating assets not placed in service and also special purpose entities' deferred issuance costs.

6. FEDERAL APPROPRIATIONS

Appropriations consist primarily of the power portion of Corps and Reclamation capital investments that had been funded through Congressional appropriations and the remaining unpaid capital investments in the BPA transmission system, which were made prior to implementation of the Federal Columbia River Transmission Act of 1974, 16 U.S.C. 838(j). Federal appropriations exclude future capital replacements and irrigation assistance.

The Refinancing Act required that the outstanding balance of the FCRPS federal appropriations be reset and assigned market rates of interest prevailing as of Oct. 1, 1996. This resulted in a determination that the principal amount of appropriations should be equal to the present value of the principal and interest that would have been paid to the U.S. Treasury in the absence of the Refinancing Act, plus $100 million. Appropriations in the amount of $6.6 billion were subsequently refinanced for $4.1 billion. This adjustment was recorded as a capitalization adjustment in regulatory liabilities and is being amortized over the remaining period of repayment.

Prior to the mid-1990s, construction and replacement of Corps and Reclamation generating facilities were financed through federal appropriations to the Corps and Reclamation. Annual appropriations were also made for operation and maintenance costs, to be repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the Energy Policy Act of 1992, in lieu of Congressional appropriations, BPA directly funds most operation and maintenance expenses as well as 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. Federal appropriations may be paid early without penalty.

The weighted average interest rate was 6.6 percent on outstanding appropriations as of Sept. 30, 2008.

MATURING FEDERAL APPROPRIATIONS

As of Sept. 30 — thousands of dollars

2009	$ 9,889
2010	3,784
2011	21,232
2012	24,622
2013	18,250
2014 and thereafter	4,180,084
	$ 4,257,861

7. BORROWINGS FROM U.S. TREASURY

At Sept. 30, 2008, of the total $2.2 billion of outstanding bonds, $725.5 million were conservation and renewable resource loans and grants (including Corps, Reclamation and U.S. Fish and Wildlife Service capital investments). The weighted average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently by BPA. As a result, the fair value of BPA U.S. Treasury borrowings exceeded the carrying value by approximately $110 million and $94 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2008, and 2007, respectively, for similar maturities.

The weighted average interest rate on outstanding U.S. Treasury borrowings was 5.2 percent and 5.4 percent as of Sept. 30, 2008, and 2007, respectively.

MATURING DEBT

As of Sept. 30 — thousands of dollars

2009	$ 440,400
2010	365,000
2011	325,000
2012	265,000
2013	122,800
2014 through 2037	667,700
	$ 2,185,900

8. NONFEDERAL DEBT

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

	2008	2007
Terminated nuclear facilities:		
Nuclear Project No. 1	**$ 1,863,790**	$ 1,938,640
Nuclear Project No. 3	**1,811,025**	1,909,430
Trojan	**—**	8,195
Terminated nuclear facilities	**3,674,815**	3,856,265
Nonfederal generation:		
Columbia Generating Station	**2,359,765**	2,327,420
Cowlitz Falls	**132,880**	137,810
Nonfederal generation	**2,492,645**	2,465,230
Lease financing program	**245,132**	170,657
Sponsored conservation:		
CARES	**18,345**	20,520
Tacoma	**11,005**	12,315
Emerald	**205**	441
Sponsored conservation	**29,555**	33,276
Northern Wasco	**24,725**	25,625
	$6,466,872	**$6,551,053**

BPA has acquired all or part of the generating capability of three nonoperating nuclear projects. These projects are 100 percent of Energy Northwest Nuclear Project No. 1, 70 percent of Nuclear Project No. 3, and 30 percent of the Trojan project owned by Eugene Water and Electric Board, Portland General Electric and PacifiCorp. The contracts to acquire the generating capability of the nonoperating nuclear projects require BPA to pay all or part of the projects' annual budgets, including maintenance expense and debt service on bonds issued by nonfederal entities. Project 1 and Project 3 were terminated prior to completion. PGE continues to decommission the Trojan project.

BPA acquired all of the generating capability of CGS nuclear generating project (formerly Project 2) and Cowlitz Falls hydro project and agreed to pay the maintenance and debt service costs.

The underlying debt for these Energy Northwest obligations (comprising terminated nuclear facilities and nonfederal generation) matures through 2024 with interest rates that are primarily fixed at rates between 3.6 percent and 7.3 percent.

Under the Lease Financing Program, BPA consolidates special purpose corporations that issue debt to and receive advances from nonfederal sources. Northwest Infrastructure Financing Corporation (NIFC) issued taxable bonded debt of $119.6 million. NIFC II has received advances of $90 million under a fully utilized line of credit with Citibank. NIFC III has received advances of $35.5 million as of Sept. 30, 2008, and has irrevocable commitments to receive additional advances of $73.8 million under a $200 million line of credit with JPMorgan Chase. The bonds and bank credit facilities are included in nonfederal debt in the accompanying Combined Balance Sheets. The debt matures through 2034 with interest rates that are primarily fixed at rates between 4.2 percent and 6.2 percent. The weighted average interest rate was 5.2 percent on the NIFCs' outstanding debt as of Sept. 30, 2008.

BPA has agreed to fund debt service on Emerald People's Utility District loans, Conservation and Renewable Energy System and City of Tacoma Conservation bonds, all issued to finance conservation programs sponsored by BPA.

BPA acquired the generating capacity of Northern Wasco hydro project which was terminated prior to completion.

Related assets for operating projects are included in nonfederal generation. Nonoperating projects are included in regulatory assets.

Nonfederal debt includes both operating and nonoperating projects. BPA recognizes expenses for these projects based upon total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $249 million, $290 million and $243 million in fiscal years 2008, 2007 and 2006, respectively, which is included in operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $479 million, $343 million and $338 million for fiscal years 2008, 2007 and 2006, respectively, is reflected as nonfederal expense in the accompanying Combined Statements of Revenues and Expenses.

The fair value of Energy Northwest debt exceeded recorded value by $37 million and $303 million as of Sept. 30, 2008, and Sept. 30, 2007, respectively. The valuations are based on discounted future cash flows using interest rates for similar debt which could have been issued at Sept. 30, 2008, and Sept. 30, 2007, respectively. The weighted average interest rate was 5.3 percent for the Energy Northwest Columbia Generating Station, Nuclear Project No. 1, and Nuclear Project No. 3 portion of outstanding nonfederal debt as of Sept. 30, 2008.

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

2009	$ 284,469
2010	286,097
2011	281,149
2012	439,721
2013	527,685
2014 and thereafter	4,647,751
	$ 6,466,872

9. OTHER LIABILITIES

IOU EXCHANGE BENEFITS

As a result of the Ninth Circuit Court rulings, in fiscal year 2008 the associated liability and regulatory asset for the Settlement Agreements were reduced to zero (See Note 4, Residential Exchange Program).

In fiscal year 2008, recognizing the importance of rate relief for the Northwest customers, BPA offered regional customers agreements that would provide interim monetary payments in advance of the final decisions reached in the WP-07 Supplemental Rate Case. One set of these agreements, referred to as Interim Agreements, provided certain IOUs with temporary REP benefits for their residential and small farm consumers. These payments were provided on an interim basis only, and were subject to true-up to the amount of REP benefits for FY 2008 as determined in BPA's WP-07 Supplemental Rate Case. BPA paid the IOUs interim payments of

$110.4 million under the Interim Agreements. BPA determined in the Final ROD for the WP-07 Supplemental Rate Case that the IOUs were entitled to $180 million in REP benefits for FY 2008. The true-up amount for the IOUs is, therefore, $69.6 million. Pursuant to a provision in the Interim Agreements, BPA will not make the true-up payment to the IOUs until BPA receives final approval of the WP-07 Supplemental Rates from FERC, and any subsequent legal challenges to BPA's final Record of Decision for the WP-07 Supplemental Rates, if any, are resolved.

DEFERRED CREDITS

As of Sept. 30 — thousands of dollars

	2008	2007
Customer reimbursable projects	**$ 209,367**	$ 233,849
Direct-service industries' benefits	**173,207**	226,464
Generation interconnection agreements	**157,505**	69,110
Third AC intertie capacity agreements	**107,285**	110,350
Fiber optic leasing fees	**42,594**	46,301
Federal Employees' Compensation Act	**34,478**	37,241
Settlements	**28,500**	33,500
Capital leases	**18,461**	19,020
Derivative instruments	**15,486**	2
Other	**10,616**	15,795
	$ 797,499	**$ 791,632**

Deferred credits include the following items:

- "Customer reimbursable projects" consist of advances received from customers where either the customer or BPA will own the resulting asset. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, the revenue is recognized over the life of the asset once the corresponding asset is placed in service.
- "Direct-service industries' benefits" reflect a contractual liability to Northwest aluminum companies and one paper mill for fiscal years 2009 through 2011. The contracts became effective on Oct. 1, 2006, and continue in effect through Sept. 30, 2011.
- "Generation interconnection agreements" are generators' advances held as security for requested new network upgrades and interconnection. These advances accrue interest and will be returned as credits against future transmission service on the new or upgraded lines.
- "Third AC intertie capacity agreements" reflect unearned revenues from customers related to the Third AC intertie capacity project. Revenue is being recognized over an estimated 49-year life of the related assets.
- "Fiber optic leasing fees" reflect unearned revenue related to the leasing of the fiber optic cable. Revenue is being recognized over the lease terms extending out to 2020.
- "Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.
- "Settlements" reflect payments due customers or counterparties as a result of contractual settlement agreements and

proposed settlements stemming from litigation (See Note 10, Commitments and Contingencies).

- "Capital leases" represent BPA's long-term portion of capital lease liabilities for Goshen-Drummond and Lower Valley-Teton transmission lines.
- "Derivative instruments" is the unrealized fair value loss of the derivative portfolio which includes physical power purchase and sale transactions, and interest rate swap transactions.
- "Other" consists of miscellaneous liabilities not identified above.

10. COMMITMENTS AND CONTINGENCIES

FIRM PURCHASE POWER AND SALE COMMITMENTS

As of Sept. 30 — thousands of dollars

	PURCHASES	SALES
2009	$ 41,545	$ 2,011,391
2010	26,979	2,115,681
2011	24,473	2,117,513
2012	56,852	2,036,206
2013	56,852	2,040,650
	$206,701	$10,321,441

Subscription contracts are the basis for the contractual relationship between BPA and its consumer-owned utilities. These contracts expire by Sept. 30, 2011. BPA enters into commitments to sell expected generation for future dates. If BPA forecasts a resource shortage it enters into commitments to purchase power for future dates. BPA records revenues and expenses associated with these sales and purchases in the periods that power is delivered or received.

ENDANGERED SPECIES ACT

The Northwest Power Act directs BPA 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. BPA makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program.

In addition, in the wake of certain listings of fish species under the Endangered Species Act (ESA) as threatened or endangered, BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA.

In May 2008 BPA, the Corps and Reclamation signed 10-year agreements with four Northwest tribes, Columbia River Inter-Tribal Fish Commission (CRITFC), the State of Idaho and the State of Montana. A fifth tribe is scheduled to sign the agreements in early November 2008. These agreements that are collectively referred to as the Columbia Basin Fish Accords provide for BPA to fund up to approximately $933 million over 10 years, enabling the tribes and states to continue existing programs and to implement new priority fish projects.

In return, the tribes and states commit to achieving biological objectives linked to meeting the federal agencies' statutory requirements. The parties also agree that the federal government's requirements under the ESA Clean Water Act and Northwest Power Act are satisfied for the next 10 years. The agreements specifically resolve, for these parties, ESA litigation pending before the U.S. District Court. BPA will record a liability when performance of all material conditions is met related to the executed individual contracts associated with the Columbia River Fish Accords.

IRRIGATION ASSISTANCE – SCHEDULED DISTRIBUTIONS

As of Sept. 30 — thousands of dollars

2009	$ 7,274
2010	—
2011	—
2012	1,206
2013	60,027
2014 and thereafter	615,183
	$ 683,690

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. Future irrigation assistance payments ultimately could total $684 million and are scheduled over a maximum of 66 years. 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 to the extent the costs have been determined to be beyond the ability of the irrigators 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. Irrigation assistance excludes $40.3 million for Teton Dam, which failed prior to completion, and BPA has no obligation to recover these costs.

ADDITIONAL POST-RETIREMENT CONTRIBUTIONS – FUTURE CONTRIBUTIONS

As of Sept. 30 — thousands of dollars

2009	$ 30,554
2010	31,195
2011	32,142
2012	32,791
2013	33,480
	$ 160,162

All fiscal years are estimates and subject to change.

BPA makes additional annual contributions to the U.S. Treasury in order to ensure that all federal post-retirement benefit programs provided to federal employees associated with the operation of the FCRPS are fully funded and to ensure that such costs are both recovered through rates and properly expensed. The additional contributions are based on employee plan participation and the extent to which the particular plans are underfunded. BPA paid $18 million, $21 million and $23 million to the U.S. Treasury during fiscal years 2008, 2007 and 2006, respectively. BPA calculates the additional contribution based upon employee plan participation and the extent to which the particular plans are under-funded. BPA records these amounts as expenses during the year in which they are paid.

1989 LETTER AGREEMENT

In 1989 BPA 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.

NUCLEAR INSURANCE

BPA is a member of the Nuclear Electric Insurance Limited, 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 $7.1 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $14.4 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.3 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 up to $95.8 million limited to an annual maximum of $10 million. Assessments would be included in BPA's costs and recovered through rates.

ENVIRONMENTAL MATTERS

From time to time, there are sites for which BPA, Corps or Reclamation may be identified as potential responsible parties. Costs associated with cleanup of sites are not expected to be material to the FCRPS' financial statements and would be recoverable through rates. As such, no liability has been recorded.

LITIGATION

Southern California Edison

Southern California Edison (SCE) had three separate actions pending in the U.S. Court of Federal Claims against BPA related to a power sales agreement (Sale and Exchange Agreement) between BPA and SCE. The actions challenged: 1) BPA'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 (Conversion Claim); 2) BPA's adjustment of the 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, which adjustment SCE alleged violated its power sales contract (Rate Adjustment Claim); and 3) BPA's termination of its performance under the contract due to SCE's nonperformance (Termination Claim).

With respect to the Conversion Claim, SCE's complaint sought damages in the amount of approximately $186 million. On June 5, 2006, BPA and SCE executed an agreement to settle the Conversion Claim and the Termination Claim, whereby BPA would make a settlement payment to SCE in exchange for SCE dismissing the two claims. The settlement identified three conditions precedent to final resolution: 1) SCE must obtain approval of the settlement from the California Public Utilities Commission; 2) BPA must complete a public review and comment process and subsequently reaffirm the settlement; and 3) BPA must receive a final resolution of its refund liability, if any, in the California refund proceedings. The first two conditions have been met. When the third condition is met, BPA will pay SCE $28.5 million plus interest.

In fiscal year 2006, BPA recorded a liability for the settlement with SCE because it determined that it was "probable" that the two conditions would occur and cause the proposed agreement to become final. BPA established an offsetting regulatory asset for the liability as the costs will be collected in future rates.

The Rate Adjustment Claim was settled with an agreement by BPA to pay SCE $13.4 million. BPA deposited these funds into escrow for disbursement to SCE pending the satisfaction of certain conditions, which have since occurred. BPA disbursed funds to SCE in October 2007.

DSI Service Record of Decision

On June 30, 2005, BPA issued a record of decision entitled "Bonneville Power Administration's Service to the Direct Service Industrial Customers for Fiscal Years 2007-2011" (DSI ROD). The DSI ROD established a policy framework which BPA subsequently used to develop new DSI power sales contracts for the fiscal years 2007-2011.

On Sept. 28, 2005, Alcoa, Inc., a BPA direct-service industrial customer, filed a petition for review in the United States Court of Appeals for the Ninth Circuit challenging the DSI ROD. On the same day, the Pacific Northwest Generating Cooperative, a consortium of BPA public consumer-owned utilities, filed a separate petition for review. In August 2006, additional petitions were filed challenging BPA's Supplement to the DSI ROD, issued on May 31, 2006, and the power sales contracts executed by and between BPA and the DSIs in June 2006. Additionally, in October 2006, petitions were filed challenging BPA's execution of a surplus power sales contract to serve Port Townsend Paper, a small direct-service industrial customer. The various petitions were consolidated, and briefing is complete. Oral argument was held on Nov. 7, 2007. The parties await a decision from the court. No liability has been recorded.

California Parties' Refund Claims

In a case relating to FERC proceedings concerning the California energy crisis of 2000-2001, in September 2005 the Ninth Circuit Court issued an opinion holding that FERC lacks authority under the Federal Power Act to order non-jurisdictional entities such as BPA to make refunds to counterparties. Subsequently, three California IOUs, the California Electricity Oversight Board, and the California Attorney General's Office on behalf of the California Department of Water Resources filed administrative claims with BPA under the Contract Disputes Act in the Court of Federal Claims (CFC). The claims amount to approximately $310 million in connection with BPA's energy transactions in the California Power Exchange and California Independent System Operator markets between May 2000 and June 2001. BPA denied the claims, and the California parties subsequently filed complaints with respect to their claims in the United States Court of Federal Claims. In addition, the California parties filed a writ of certiorari in the above referenced Ninth Circuit Court case at the United States Supreme Court. Argument on the motion was heard on June 24, 2008, and the Court denied the motion. BPA filed answers in October 2008 in the CFC litigation. BPA cannot determine at this time whether the claimed amount will ultimately be upheld. BPA has engaged in settlement discussions prior to the filing of these suits and continues to be open to settlement. There are a number of legal issues that will eventually be resolved by the courts that will determine whether any amounts will be accrued. At present no liability is recorded.

Rates

BPA's rates are frequently the subject of litigation. Most of the litigation involves claims that BPA's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record, or are arbitrary and capricious. It is the opinion of BPA's General Counsel that if any rate were to be rejected, the sole remedy accorded would be a remand to BPA to establish a new rate. BPA's flexibility in establishing rates could be restricted by the rejection of a BPA rate, depending on the grounds for the rejection. BPA is unable to predict, however, what new rate it would establish if a rate were rejected. If BPA 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, BPA is required by law to set rates to meet all of its costs. Thus, it is the opinion of BPA's General Counsel that BPA may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Other

The FCRPS may be affected by various other legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. BPA is unable to predict whether the FCRPS will avoid adverse outcomes in these legal proceedings or, if not, what the impact might be. BPA currently believes that disposition of pending matters will not have a materially adverse effect on the FCRPS' financial position or results of operations for fiscal year 2008.

Judgments and settlements are included in BPA's costs and recovered through rates. Except with respect to the SCE matter described above, BPA management has not recorded a liability for the above legal matters.

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Federal Columbia River Power System
Combined Balance Sheets
(Unaudited)

	December 31, 2008	September 30, 2008
	(thousands of dollars)	
Assets		
Utility plant		
Completed plant	$ 13,514,188	$ 13,480,633
Accumulated depreciation	(4,980,940)	(4,933,348)
	8,533,248	8,547,285
Construction work in progress	934,731	890,883
Net utility plant	9,467,979	9,438,168
Nonfederal generation	2,487,535	2,492,645
Current assets		
Cash	1,521,102	1,731,238
U.S. Treasury market-based special securities	9,728	-
Accounts receivable, net of allowance	115,076	112,129
Accrued unbilled revenues	255,339	203,011
Materials and supplies, at average cost	77,765	75,719
Prepaid expenses	19,835	21,682
Total current assets	1,998,845	2,143,779
Other assets		
Regulatory assets	5,404,590	5,447,404
U.S. Treasury market-based special securities	88,971	-
Nonfederal nuclear decommissioning trusts	149,223	157,743
Deferred charges and other	175,845	176,045
Total other assets	5,818,629	5,781,192
Total assets	$ 19,772,988	$ 19,855,784
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	$ 2,647,814	$ 2,664,460
Federal appropriations	4,264,536	4,247,972
Borrowings from U.S. Treasury	1,745,500	1,745,500
Nonfederal debt	6,195,423	6,182,403
Total capitalization and long-term liabilities	14,853,273	14,840,335
Commitments and contingencies (See Note 10 to annual financial statements)		
Current liabilities		
Federal appropriations	9,889	9,889
Borrowings from U.S. Treasury	405,400	440,400
Nonfederal debt	284,934	284,469
Accounts payable and other	496,107	588,275
Total current liabilities	1,196,330	1,323,033
Other Liabilities		
Regulatory liabilities	2,635,487	2,665,517
IOU exchange benefits	69,600	69,600
Asset retirement obligations	160,870	159,800
Deferred credits	857,428	797,499
Total other liabilities	3,723,385	3,692,416
Total capitalization and liabilities	$ 19,772,988	$ 19,855,784

Federal Columbia River Power System

Combined Statements of Revenues and Expenses

(Unaudited)

	Three Months Ended December 31, **2008**	Three Months Ended December 31, 2007	Fiscal Year-to-Date Ended December 31, **2008**	Fiscal Year-to-Date Ended December 31, 2007
			(thousands of dollars)	
Operating revenues				
Sales	**$ 726,519**	$ 757,045	**$ 726,519**	$ 757,045
Derivative instruments	**(39,947)**	(16,120)	**(39,947)**	(16,120)
U.S. Treasury credits for fish	**21,589**	22,955	**21,589**	22,955
Miscellaneous revenues	**14,932**	17,440	**14,932**	17,440
Total operating revenues	**723,093**	781,320	**723,093**	781,320
Operating expenses				
Operations and maintenance	**350,190**	347,565	**350,190**	347,565
Purchased power	**123,390**	133,841	**123,390**	133,841
Nonfederal projects	**123,952**	121,274	**123,952**	121,274
Depreciation and amortization	**88,000**	88,531	**88,000**	88,531
Total operating expenses	**685,532**	691,211	**685,532**	691,211
Net operating revenues	**37,561**	90,109	**37,561**	90,109
Interest expense and (income)				
Interest expense	**81,312**	79,851	**81,312**	79,851
Allowance for funds used during construction	**(8,143)**	(5,706)	**(8,143)**	(5,706)
Interest income	**(18,962)**	(18,529)	**(18,962)**	(18,529)
Net interest expense	**54,207**	55,616	**54,207**	55,616
Net (expenses) revenues	**$ (16,646)**	$ 34,493	**$ (16,646)**	$ 34,493

Report of Independent Auditors

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, 2008, and the related statements of operations and fund equity and of 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, 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 audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the basic financial statements are free from material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the basic 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 audit provides a reasonable basis for our opinions.

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 at June 30, 2008, 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 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. We have applied certain limited procedures, which consisted principally of inquiries of management, regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

Portland, Oregon
September 25, 2008

Energy Northwest 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 (FY) ended June 30, 2008, with the basic financial statements for the FY ended June 30, 2007. Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest's records are maintained as prescribed by the Governmental Accounting Standards Board (GASB) and, when not in conflict with GASB pronouncements, accounting principles prescribed by the Financial Accounting Standards Board (FASB). (SEE NOTE B TO THE FINANCIAL STATEMENTS).

Because each business unit is financed and accounted for separately, the following section on financial performance is discussed by business unit to aid in analysis of assessing the financial position of each individual business unit. For comparative purposes only, the table on the following page represents a memorandum total only for Energy Northwest, as a whole, for FY 2008 and FY 2007 in accordance with GASB No. 34, "Basic Financial Statements-and Management's Discussion and Analysis-for State and Local Governments."

The financial statements for Energy Northwest include the Balance Sheets, Statements of Operations and Fund Equity, the Statements of Cash Flows for each of the business units and Notes to Financial Statements.

The Balance Sheets present the financial position of each business unit on an accrual basis. The Balance Sheets report financial information about construction work in progress, the amount of resources and obligations, restricted accounts and due to/from balances (see Note B to the Financial Statements) for each business unit.

The Statements of Operations and Fund Equity provide financial 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. The financial information provided aids in benchmarking activities, conducting comparisons to evaluate progress, and determining whether the business unit has successfully recovered its costs.

The Statements of Cash Flows 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 purpose of cash activity.

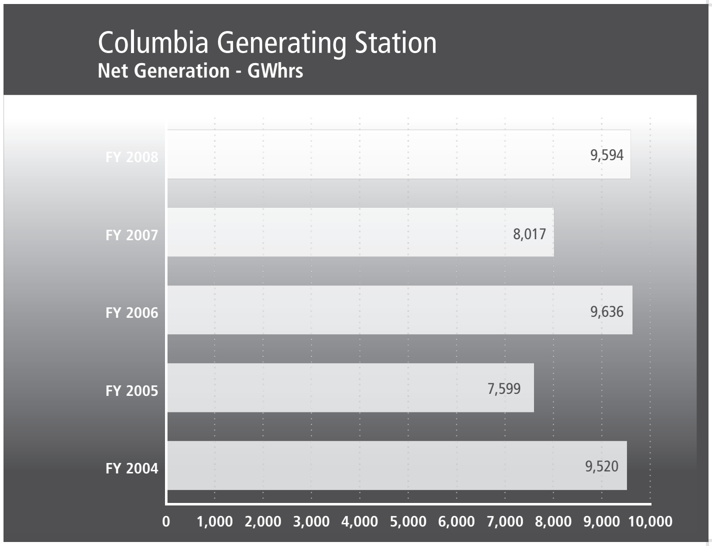
The Notes to Financial Statements present disclosures that contribute to the understanding of the material presented in the financial statements. This includes, but is not limited to; Schedule of Outstanding Long-Term Debt and Debt Service Requirements (see Note E – Long-Term Debt), accounting policies, significant balances and activities, material risks, commitments and obligations and subsequent events, if applicable.

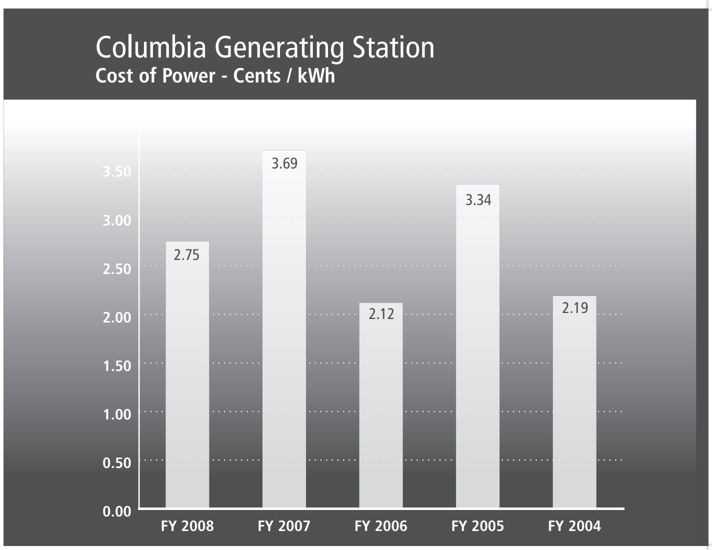
The basic financial statements of each business unit should be used individually along with the notes to the financial statements and the management discussion and analysis to provide an overview of Energy Northwest's financial performance. Questions concerning any of the information provided in this report should be addressed to Energy Northwest at PO Box 968, Richland, WA, 99352.

COMBINED FINANCIAL INFORMATION

June 30, 2008 and 2007 (000's)

	2007	2008	Change
Assets			
Net Plant	$ 1,512,222	$ 1,509,814	$ (2,408)
Nuclear Fuel	235,742	208,082	(27,660)
Current and Restricted Assets	497,562	592,034	94,472
Long-term Receivables and Deferred Charges	4,517,173	4,492,382	(24,791)
TOTAL ASSETS	$ 6,762,699	$ 6,802,312	$ 39,613
Fund Equity	$ (7,667)	$ (10,045)	$ 2,378
Long-Term Debt	$ 6,379,097	$ 6,290,766	$ 88,331
Restricted and Non-current Liabilities	274,625	267,753	(6,872)
Current Liabilities	113,504	247,918	134,414
Deferred Credits	3,140	5,920	2,780
TOTAL EQUITY AND LIABILITIES	$ 6,762,699	$ 6,802,312	$ 39,613
Operating Revenues	$ 452,402	$ 455,066	$ 2,664
Operating Expenses	355,675	336,622	(19,053)
Net Operating Revenues	$ 96,727	$ 118,444	$ 21,717
Other Income and Expense	$ (105,136)	$ (120,337)	$ (15,201)
Distribution and Contributions	771	(485)	(1,256)
Beginning Fund Equity	(29)	(7,667)	(7,638)
ENDING FUND EQUITY	$ (7,667)	$ (10,045)	$ (2,378)





COLUMBIA GENERATING STATION

The Columbia Generating Station (Columbia) is owned by Energy Northwest and its Participants and operated by Energy Northwest. The plant is a 1,150 megawatt electric (MWe, Design Electric Rating, net) boiling water nuclear power station located on the Department of Energy's (DOE) Hanford Reservation north of Richland, Washington.

Columbia had its second best fiscal year generation on record bettered only by the continuous daily record run for FY 2006. Columbia produced 9,594 gigawatt-hours (GWh) of electricity in FY 2008, as compared to 8,017 GWh of electricity in FY 2007, which included economic dispatch of 134 GWh and 33 GWh respectively. Columbia was in the off cycle year for its two-year refueling and maintenance outage which was the major reason for the increase in generation from FY 2007 to FY 2008.

Columbia's performance is measured in several ways, including cost of power at Columbia. The cost of power for FY 2008 was 2.75 cents per kilowatt-hour (kWh) as compared with 3.69 cents per kWh in FY 2007. The industry cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. Higher generation figures for FY 2008 combined with cost underruns for operations and maintenance and capital costs were the major drivers for the lower cost of power from FY 2007.

Balance Sheet Analysis

The net decrease to Plant in Service and Construction Work In Progress (CWIP) from FY 2007 to FY 2008 (excluding nuclear fuel) was $44.8 million. The additions to Plant/CWIP of $26.9 million were offset by an increase to Accumulated Depreciation of $71.7 million resulting in the net decrease to plant of $44.8 million. The additions to plant for FY 2008 were captured in seven major projects (Condenser Module Replacement, Reactor Recirculation Motor Refurbishment, Reactor Manual Control System Upgrade, Upgrade Enterprise Project Management Database, Intrusion Detection System Improvement, Emergency Preparedness Order B.5.b Driven Upgrades, and Radiation Monitor Replacements); these projects resulted in 44 percent of the additions to plant. The remaining 56 percent of additions were made up of 83 separate projects.

Nuclear fuel, net of accumulated amortization, decreased $27.7 million from FY 2007 to $208.1 million for FY 2008. During FY 2008 Columbia incurred $6.6 million in capitalized fuel purchases. There was a bi-annual write-off of fuel and amortization for the removal of fuel assemblies related to the maintenance and refueling outage (R-18). The write-off of $54.4 million represents the original cost of the fuel assemblies removed and those that are past the required six month cooling period per Federal Energy Regulatory Commission (FERC) guidelines. The write-off amount was offset by $20.1 million in current year amortization.

The Restricted Assets Special Funds increased $27.7 million from FY 2007 levels to $91.1 million in FY 2008 due to the FY 2008 bond financing plan and schedule of construction cost for these funds in FY 2009.

The Debt Service Funds increased $3.7 million in FY 2008 to $58.0 million. The increase was created from funding increases in FY 2008 due to borrowing activities.

Long-term receivables decreased $1.1 million in FY 2008 to $34k reflecting the estimate of current use of the negotiated receivable and anticipated costs for FY 2009.

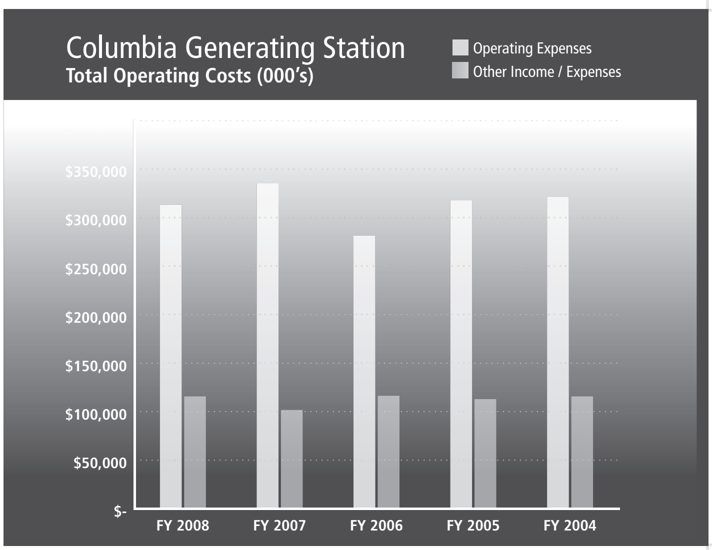
Current assets decreased $40.5 million in FY 2008 to $134.9 million. The main cause of this decrease was due to timing of cash outlay for FY 2007 expenses which amount to approximately $30 million. The remaining difference was due to lower operating activities from the previous year.

Deferred charges increased $114.7 million in 2008 from $694.5 million to $809.2 million. Components of this increase were an increase to Costs in Excess of Billings of $110.0 million, increase for relicensing of $5.4 million and a slight decrease to unamortized debt expense of $0.7 million. The increase to Costs in Excess of Billings was due to refunding current maturities while extending the overall maturities on the refunding debt. In addition, the accumulated decommissioning and site restoration accrued costs are not currently billed to Bonneville Power Administration (BPA). BPA holds and manages a trust fund for the purpose of funding decommissioning and site restoration (see Note B to the Financial Statements, "Decommissioning and Site Restoration"). The balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet.

Columbia was issued a standard 40-year operating license by the Nuclear Regulatory Commission (NRC) in 1983. Energy Northwest is in the initial phase of preparing an application to renew the license for an additional 20 years, thus continuing operations to 2043. Submittal of this application is anticipated in the second half of FY 2009. The estimated license renewal process is 18-24 months from acceptance of application.

Long-Term Debt increased $43.8 million in FY 2008 from $2.39 billion to $2.44 billion, excluding current maturities, which was a result of the FY 2008 Bond Issue. In FY 2008, new debt was issued for various Columbia construction projects, as well as for part of the Debt Optimization Program (see Note E to the Financial Statements).

Through June 30, 2006, Energy Northwest was being paid by the participants for Net Billings. The payments were based on a percentage of ownership in Columbia and Nuclear Projects No. 1 and 3 and reflected budgeted costs for operations of the fiscal year. Beginning in FY 2007, Energy Northwest began billing Bonneville Power Administration on a monthly basis for estimated expenses, not to exceed the approved budget, instead of billing and receiving the participants' legal obligations. The change in billing arrangement does not impact the Net Billing Agreements for Columbia and Nuclear Projects No. 1 and 3.



Statement of Operations Analysis

Columbia 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.

Operating expenses decreased $22.0 million from FY 2007 to $313.2 million due to less activity related to the off cycle year of the two year refueling and maintenance program. Operations and Maintenance decreased $37.7 million which is attributable to the off cycle year. The decrease in operations and maintenance was offset by higher fuel costs of $12.0 million due to the increased generation levels from FY 2007 and the associated increase in generation taxes of $1.5 million. Other offsets to the operating expense decrease is a $3.6 million increase to Administrative and General relating to staffing requirements, related benefit increases, and increased regulatory expenses. There was a slight decrease to the Decommissioning and Depreciation accounts of $1.4 million.

Other Income and Expenses increased $14.0 million from FY 2007 to $115.8 million net expenses in FY 2008. The main driver of change to these accounts was the net effects of Columbia debt (see Note E to the financial statements). However in FY 2007, there was $12.6 million in a building sale and loaned fuel revenue that did not happen in FY 2008. This change was offset slightly by an increase in miscellaneous activity resulting in revenue of $1.3 million. The remaining $2.7 million increase was related to the net effects of Columbia debt activity.

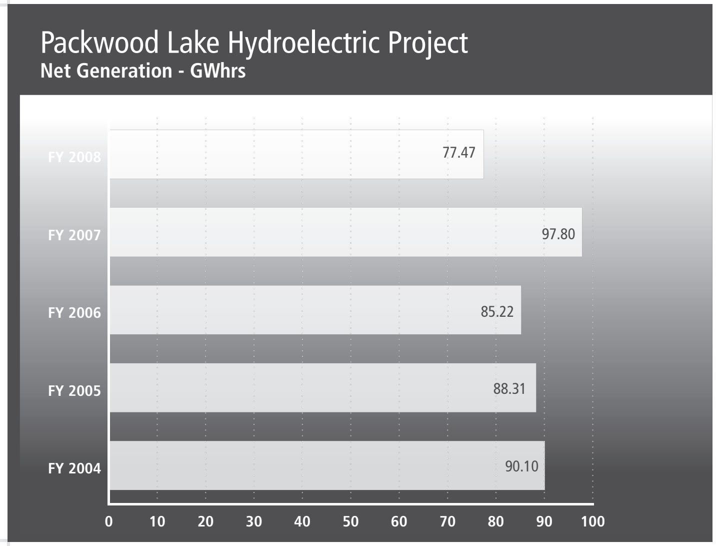
Columbia total operating revenue decreased from $437.0 million in FY 2007 to $429.0 million in FY 2008. The decrease of $8.0 million is due to the off cycle year of the two year refueling and maintenance program and the related effect of the net billing agreements on total revenue.

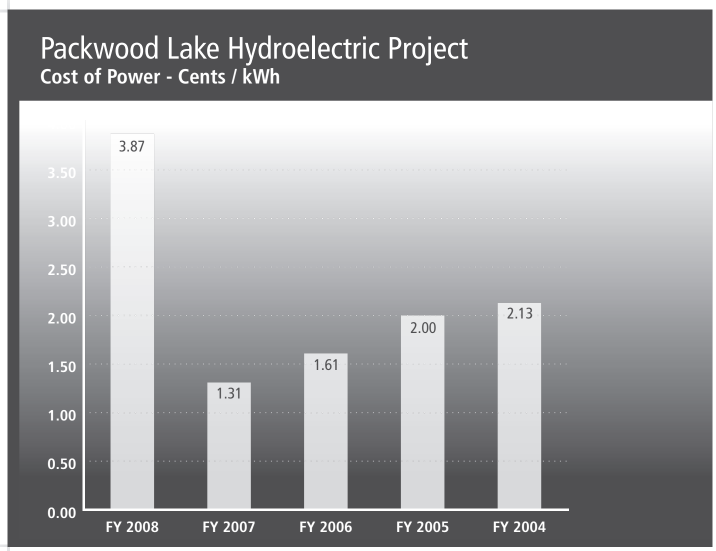
PACKWOOD LAKE HYDROELECTRIC PROJECT

The Packwood Lake Hydroelectric Project (Packwood) is owned and operated by Energy Northwest. Packwood consists of a dam at Packwood Lake and a powerhouse 1,800 feet below the dam that is located south of Packwood, Washington. Packwood produced 77.47 GWh of electricity in FY 2008 versus 97.80 GWh in FY 2007. Due to unusually poor water conditions Packwood experienced its lowest generation levels in seven years. These water conditions reflected the opposite scenario prevalent in FY 2007 which had generation at 6.3 percent above the 30 year average of 92 GWh.

In November 2006, Lewis County was declared a disaster area because of torrential rain and flooding. During this event a large landslide occurred adjacent to the Packwood underground pipeline. Significant repairs to the pipeline support were completed during the year. Expenditures totaled $1.0 million to install barriers and improve drainage to mitigate the recurrence of another event. The project applied for "Public Assistance Grants" from the Washington State Military Department (Emergency Management Division) and Federal Emergency Management Agency (FEMA) in FY 2007 and the acceptance is pending. Due to the delay in grant acceptance a bank line of credit was established for $1.3 million while grant acceptance from FEMA is being resolved. To date, $0.8 million has been borrowed against the line of credit.

Packwood's performance is measured in several ways, including cost of power. The cost of power for FY 2008 was $3.87 cents/kWh as compared to $1.31 cents/kWh in FY2007. The cost of power fluctuates year to year depending on various factors such as outage maintenance and other operating activities. The FY 2008 cost of power increase was due to costs of buying power to meet contract obligations when lower than projected water runoff reduced generation and the costs of the landslide repair.

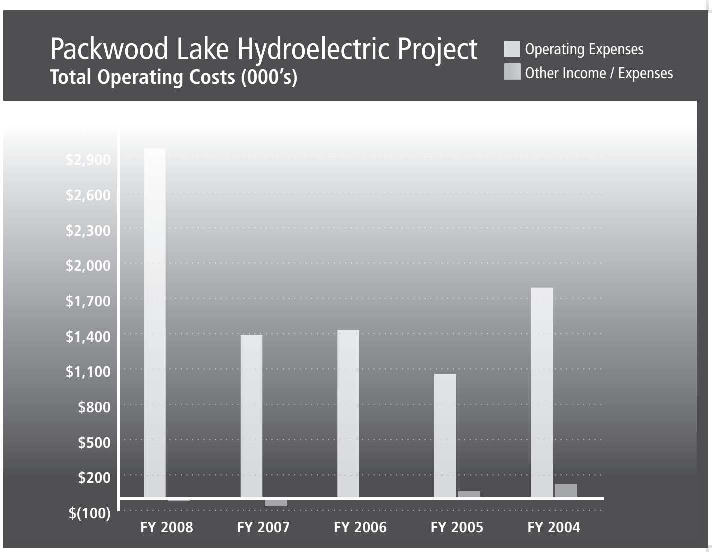




Balance Sheet Analysis

Total assets increased $1.6 million from FY 2007, with $1.0 million of the increase due to costs incurred and capitalized for the relicensing effort, $0.5 million increase to plant related to fish barrier requirements, increase to receivables of $0.2 million related to energy sales, with the remainder being a component of bond and investment activity. Significant changes to total liabilities included a decrease in Revenue Bonds Payable of $0.7 million, recognition of the $0.8 million relating to the line of credit, increase in Deferred Credits of $2.1 million due to operations, relicensing and bond retirements, with the remainder being amounts due from power purchasers as well as amounts due from other business units related to results of operations. No new debt was issued and the total debt continues to decrease per the current debt schedules. Similar to the previous fiscal year, there was no excess funding accrued in FY 2008. Participants have agreed to retain all excess within the Packwood business unit for relicensing efforts.

Packwood has incurred $3.4 million in relicensing costs through FY 2008. These costs are shown as Deferred Charges on the Balance Sheet. The FY 2009 projections call for an additional $0.5 million in costs to continue the relicensing efforts. The FERC issued a fifty-year operating license to Packwood on March 1, 1960. The current license will expire on February 28, 2010. The final application for the relicensing of Packwood was submitted to FERC on February 22, 2008.



Statement of Operations Analysis

The agreement with Project Participants (see Note A to the Financial Statements) obligates them to pay annual costs and to 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.

Operating expenses increased $1.6 million due to slide repair work of $0.9 million and increased purchased power costs of $0.7 million related to poor water conditions.

Packwood is obligated to supply a specified amount of power. If power production from Packwood does not supply the required amount of power, the shortfall is provided by purchasing power on the open market. The increase in FY 2008 expenses reflects this requirement. Conversely, if there is excess capacity per the power sales agreement with Benton and Franklin PUDs, Energy Northwest sells the excess on the open market for additional revenues to be included as part of the power purchase agreements with the participants of the Project (see Note E, Long-Term Debt, "Security – Packwood Lake Hydroelectric Project").

Other income and expenses decreased from a net income of $65k in FY 2007 to $11k in FY 2008. The decrease was due to lower invested amounts as these funds were used to fund the increased cost of operations for FY 2008. Investment income decreased $59k from FY 2007 which was offset by a decrease to bond related expenses of $6k.

NUCLEAR PROJECT NO. 1

Energy Northwest wholly owns 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 a resolution terminating Nuclear Project No. 1. All funding requirements are net-billed obligations of Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity on Nuclear Project No. 1 and are net-billed.

Balance Sheet Analysis

Under the Debt Optimization Program, long-term debt decreased $50.0 million from $1.976 billion in FY 2007 to $1.926 billion in FY 2008 due to debt restructuring to take advantage of lower interest rates.

Statement of Operations Analysis

Other Income and Expenses showed a net decrease to non-operating revenues of $7.7 million from $113.4 million in FY 2007 to $105.7 million in FY 2008. There was a recognized decrease to other revenue of $3.9 million reflecting less surplus sales activity but this was offset by lower bond related expenses of $8.6 million, decreased costs for decommissioning and plant preservation of $2.6 million and increased revenues from investment income of $0.4 million.

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 a resolution 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, Commitments and Contingencies). The debt service related activities remain and are net-billed.

Balance Sheet Analysis

Under the Debt Optimization Program, long-term debt decreased $16.6 million from $1.853 billion in FY 2007 to $1.774 billion in FY 2008 due to debt restructuring to take advantage of lower interest rates. Included in the FY 2008 long-term debt is the current portion of $95.2 million.

Statement of Operations Analysis

Overall expenses decreased $3.3 million from FY 2007. Bond related expenses decreased $3.7 million as a result of the debt restructuring. The remaining change in other expenses was a combination of lower investment income of $0.2 million due to market conditions and a slight increase of $0.2 million for treasury and termination activities.

BUSINESS DEVELOPMENT FUND

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. 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. Four business sectors have been created within the fund: General Services and Facilities, Generation, Professional Services and Business Unit Support. Each sector may have one or more programs that are managed as a unique business activity.

Balance Sheet Analysis

Total assets increased $3.1 million from $3.2 million in FY 2007 to $ 6.3 million in FY 2008. Most of the increase was due to revenue and related cash for sale of the Reardan Twin Buttes Wind Project of $2.3 million. Other changes of $0.7 million were due to normal results of operations and reflected nominal changes in receivables from customers and other business units. Liabilities were relatively steady from FY 2007 to FY 2008 showing a small increase of $15k for the year. Fund Equity increased $3.1 million from $1.4 million in FY 2007 to $4.5 million in FY 2008. The increase was due to the wind mining project revenue offset slightly by a decrease in results of operations.

Statement of Operations Analysis

Operating Revenues in FY 2008 totaled $10.5 million as compared to FY 2007 revenues of $7.6 million, an increase of $2.9 million. Most of the revenue increase over FY 2007 is attributable to the $2.3 million sale of the Reardan Twin Buttes Wind Project. The remaining increases to revenues are from calibration laboratory services and leasing revenue of approximately $0.4 million each offset by a decrease of $0.2 million in generation development lines.

Net operations for FY 2008 showed an operating profit of $0.6 million, up $3.2 million from the FY 2007 operating loss of $2.6 million which reflects the Reardan project and net business line activity.

Major power generation development activities included converting the Pacific Mountain Energy Center (PMEC) to a Natural Gas Combined Cycle (NGCC) to comply with a new State of Washington CO_2 standard, and seeking new utility investors. The new NGCC project is called Kalama Energy.

Kalama Energy is a 680 MWe NGCC generation plant located in Western Washington. The project development will be based on preselling the project with at-cost power options for member utilities and an Energy Northwest O & M agreement. Additional expansion options will be negotiated for future public power resources.

The generation development team had a successful wind development year including the sale of Reardan Twin Buttes Wind Project for $2.3 million and initiating feasibility and predevelopment activities on two additional projects in the Northwest. The 32.2 MW Nine Canyon Phase III project was successfully constructed and began commercial operation in May 2008.

The Business Development Fund receives contributions from the Internal Service Fund to cover cash needs during startup periods. Initial startup costs are not expected to be paid back and are shown as contributions. As an operating business unit, requests can be made to fund incurred operating expenses. In FY 2008, the Business Development Fund received contributions (transfers) of $2.5 million, up from the $1.8 million amount in FY 2007.

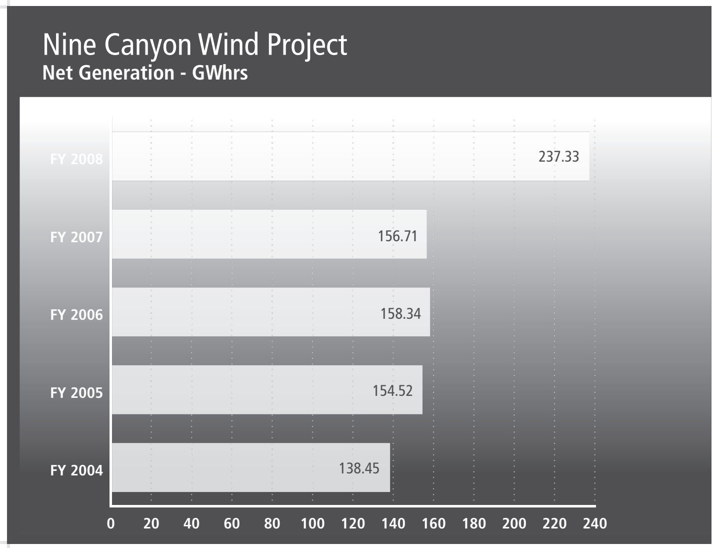
NINE CANYON WIND PROJECT

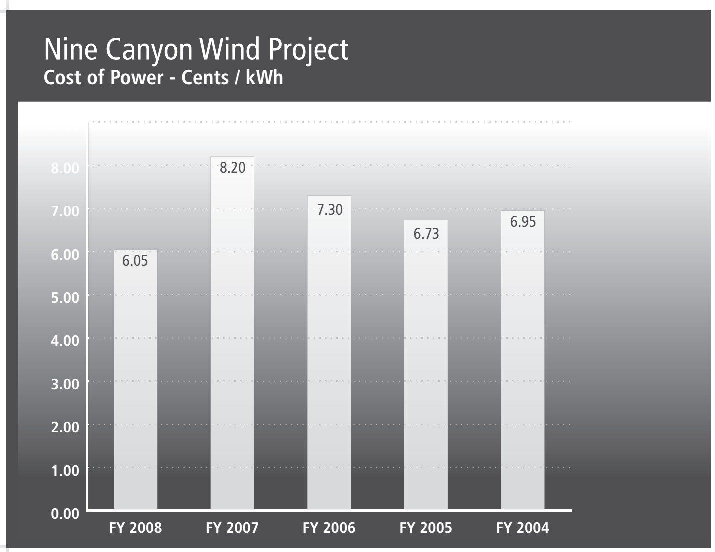
The Nine Canyon Wind Energy Project (Nine Canyon) is owned and operated by Energy Northwest. Nine Canyon is located in the Horse Heaven Hills area southwest of Kennewick, Washington. Electricity generated by Nine Canyon is purchased by Pacific Northwest Public Utility Districts (purchasers). Each purchaser of Phase I has signed a 28-year power purchase agreement with Energy Northwest; each purchaser of Phase II has signed a 27-year power purchase agreement, and each purchaser of Phase III has signed a 23-year power purchase agreement. The agreements are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Purchase Agreement which now have an agreement end date of 2030. Nine Canyon is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by the Benton County Public Utility District.

Phase I of Nine Canyon, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 MW, for a total capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 12 wind turbines with an aggregate generating capacity of approximately 15.6 MW. Phase III of Nine Canyon was declared operational on May 8, 2008, and includes 14 wind turbines, each with a maximum generating capacity of 2.3 MW, for an aggregate generating capacity of 32.2 MW. The total Nine Canyon generating capability is 95.9 MW, which produces enough energy for approximately 39,000 average homes.

Nine Canyon produced 237.33 GWh of electricity in FY2008 versus 156.71 GWh in FY2007. The increase in production was due to an increase in the capacity factor because of higher than projected wind and the addition of the Phase III turbines.

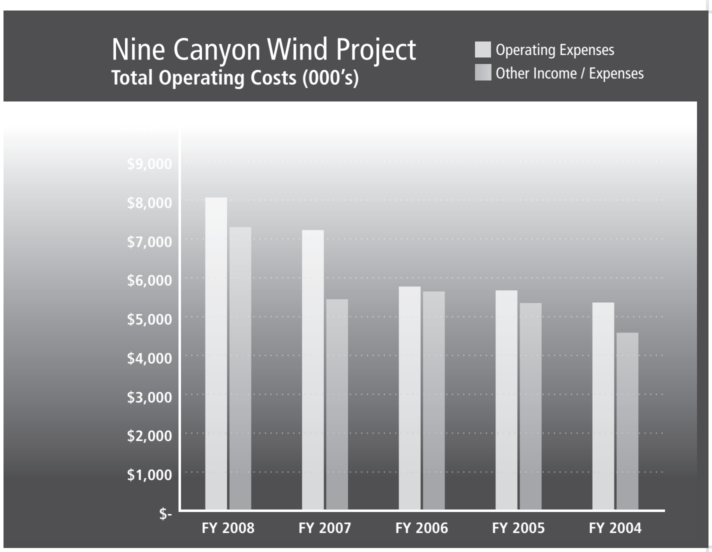
Nine Canyon's performance is measured in several ways, including cost of power. The cost of power for FY 2008 was $6.05 cents/kWh as compared to $8.20 cents/kWh in FY 2007. The cost of power fluctuates year to year depending on various factors such as wind totals and unplanned maintenance. The FY 2008 cost of power decrease was mostly due to better than projected wind conditions and the addition of the more efficient Phase III turbines.





Balance Sheet Analysis

Assets decreased $3.6 million from $148.4 million in FY 2007 to $144.8 million in FY 2008. Utility plant increased $43.7 million due to Phase III construction and there were decreases to restricted assets involving cash and investments and unamortized debt expense of $53.8 million associated with the construction costs of Phase III and a $0.1 million reduction in the Renewable Energy Performance Incentive (REPI) payment accrued. The FY 2008 REPI accrual was $0.7 million compared to $0.8 million for FY 2007. The remaining change in assets was an increase of $6.6 million due to excess funds from the 2006 Revenue Bonds. Construction costs came in under the estimate used for the 2006 bond sale and will be used to pay future costs of the project. There was a small overall decrease to liabilities of $0.6 million with increases to decommissioning of $0.4 million, due to Phase III; increase in deferred charges relating to turbine elevators of $0.3 million with offsets to bond and accrued cost decreases of $1.3 million. The decrease in Fund Equity was $2.9 million in FY 2008 as compared to $5.6 million in FY 2007. The decline experienced in previous years is continuing, though slowed from previous periods. The original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires. The REPI incentive expires ten years from the initial operation startup date for each Phase. Reserves that were established are used to facilitate this plan. The rate plan in FY 2008 was revised to account for the shortfall experienced in the REPI funding and to provide a new rate scenario out to the 2030 project end date.



Statement of Operations Analysis

Operating Revenues increased from $6.5 million in FY 2007 to $12.6 million in FY 2008. The project received revenue from the billing of the project purchasers at an average rate of $51.83 per MWh for FY 2008. The increase in revenue from FY 2007 was due to a revised rate plan that was implemented in FY 2008. The rate plan was revised to account for REPI funding shortfalls and costs of operations. There was a slight increase in operating expenses of $0.8 million from $7.2 million in FY 2007 to $8.0 million in FY 2008. Change in operating expenses was due to increased depreciation costs of $0.5 million due to plant additions with the remaining $0.3 million increase due to miscellaneous operating costs. Other revenue and expenses increased $1.9 million from FY 2007 to $7.3 million in FY 2008. Investment income associated with bond funds decreased $0.2 million due to use of construction funds for Phase III. Bond interest increased $1.7 million from the previous year based on the debt service schedule for the Phase I, II and III projects. Net losses of $2.8 million for FY 2008 continued the trend from previous years. This trend is reflected in the declining Fund Equity balance. However, the balance is considerably improved over the loss reported for FY 2007 of $6.2 million and the trend reflects the revised rate structure.

Energy Northwest has accrued, as income (contribution) from the DOE, Renewable Energy Performance Incentive (REPI) payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI bill. 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. Nine Canyon recorded a receivable for the applied REPI funding in the amount of $0.7 million for FY 2008, representing its share of funded amounts. The payment stream from Nine Canyon participants and the REPI receipts were projected to cover the total costs over the purchase agreement. Permanent shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project. The billing rates for the Nine Canyon participants increased 69 percent and 80 percent for Phase I and Phase II participants respectively in FY 2008 in order to cover total Project costs and are projected out to the 2030 proposed project end date. The increases for FY 2008 were a change from the previous plan where a 3 percent increase each year over the life of the project was projected. Going forward, the increase or decrease in rates will be based on the cash requirements of debt repayment and the cost of operations. Phase III started with an initial planning rate of $49.82 per MWh which will increase at 3 percent for three years. In year four the rate will increase to a rate that will be stabilized over the life of the project. Possible adjustments may be necessary to future rates depending on operating costs and REPI, similar to Phase I and II.

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).

Balance Sheet Analysis

Total Assets for FY 2008 decreased $5.8 million from $43.2 million in FY 2007 to $37.4 million in FY 2008. The three major items for the change were a decrease to the performance fee investment account of $2.5 million, a decrease to net plant of $1.7 million due to change in accumulated depreciation, and a decrease of $2.3 million due from other business units related to end year obligations, which was partially offset by $0.6 million in fund obligations at year end. Small overall increase of assets for $0.1 million consisted of cash and investments relating to operations.

The net decrease in Fund Equity and Liabilities is due to a decrease to payroll related expenses of $1.1 million, $3.5 million in current liabilities related to Accounts Payables non-outage year activity. Other decreases of $2.5 million in Fund Equity related to the performance fee drawdown, offset by increases of $1.3 million related to amounts due to other business units.

Statement of Operations Analysis

Net Revenues for FY 2008 increased slightly ($26k) from FY 2007. Investment income decreased $164k due to lower invested balance relating to the drawdown of the performance fee account and lower yields. Net rental revenues for available buildings at corporate headquarters increased $182k as lease utilization was considerably higher in FY 2008, with daily operations resulting in the remainder of change for FY 2008.

BALANCE SHEETS

As of June 30, 2008 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2008 Combined Total
Assets									
UTILITY PLANT (NOTE B)									
In service	$ 3,579,571	$ 13,559	$ -	$ -	$ 1,327	$ 133,217	$ 3,727,674	$ 47,086	$ 3,774,760
Not in service			25,253				25,253		25,253
Accumulated depreciation	(2,246,411)	(12,517)	(25,253)		(548)	(20,219)	(2,304,948)	(37,790)	(2,342,738)
	1,333,160	1,042	-	-	779	112,998	1,447,979	9,296	1,457,275
Nuclear fuel, net of accumulated amortization	208,082						208,082		208,082
Construction work in progress	52,539						52,539		52,539
	1,593,781	1,042	-	-	779	112,998	1,708,600	9,296	1,717,896
RESTRICTED ASSETS (NOTE B)									
Special funds									
Cash	8,106		4	37		1	8,148	361	8,509
Available-for-sale investments	82,954		11,855	12,493		1,575	108,877	1,484	110,361
Accounts and other receivables						655	655		655
Debt service funds									
Cash	55,870	7	115	2,328		7,984	66,304		66,304
Available-for-sale investments	106	747	96,457	123,497		11,709	232,516		232,516
Due from other funds	2,010	1,081	1,693				4,784		-
	149,046	1,835	110,124	138,355	-	21,924	421,284	1,845	418,345
LONG-TERM RECEIVABLES (NOTE B)	34	-	-	-	-	-	34	-	34
CURRENT ASSETS									
Cash	12,776	2	928	1,038	3,406	1,407	19,557	1,514	21,071
Available-for-sale investments	9,652	2	6,124	7,024	960	5,090	28,852	23,158	52,010
Accounts and other receivables	785	467	2		522		1,776	124	1,900
Due from Participants		875					875		875
Due from other business units	942	217	515		590		2,264	1,462	-
Due from other funds	12,963		6,427	40,207		591	60,188		-
Materials and supplies	96,444						96,444		96,444
Prepayments and other	1,301	59	2		21		1,383	6	1,389
	134,863	1,622	13,998	48,269	5,499	7,088	211,339	26,264	173,689
DEFERRED CHARGES									
Costs in excess of billings	791,302		1,913,071	1,746,070			4,450,443		4,450,443
Unamortized debt expense	12,514		10,077	7,776		2,709	33,076		33,076
Other deferred charges	5,410	3,419					8,829		8,829
	809,226	3,419	1,923,148	1,753,846	-	2,709	4,492,348	-	4,492,348
TOTAL ASSETS	$ 2,686,950	$ 7,918	$ 2,047,270	$ 1,940,470	$6,278	$ 144,719	$ 6,833,605	$37,405	$ 6,802,312

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

BALANCE SHEETS (CONT'D)

As of June 30, 2008 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2008 Combined Total
Fund Equity and Liabilities									
FUND EQUITY									
Invested in capital assets, net of related debt	$ -	$ -	$ -	$ -	$ 779	$ (42,676)	$ (41,897)	$ 9,296	$ (32,601)
Restricted, net						16,260	16,260	1,484	17,744
Unrestricted, net					3,704	5,461	9,165	(4,353)	4,812
	-	-	-	-	4,483	(20,955)	(16,472)	6,427	(10,045)
LONG-TERM DEBT (NOTE E)									
Revenue bonds payable	2,359,765	551	1,863,790	1,811,025		148,435	6,183,566		6,183,566
Unamortized (discount)/premium on bonds - net	95,341	(1)	93,716	(22,208)		5,633	172,481		172,481
Unamortized gain/(loss) on bond refundings	(19,336)	14	(31,404)	(14,555)			(65,281)		(65,281)
	2,435,770	564	1,926,102	1,774,262	-	154,068	6,290,766	-	6,290,766
LIABILITIES- PAYABLE FROM RESTRICTED ASSETS (NOTE B)									
Special funds									
Accounts payable and accrued expenses	112,995		14,270			1,052	128,317	361	128,678
Due to other funds	14,973		8,120	8,871		591	32,555		-
Debt service funds									
Accrued interest payable	51,885	16	44,106	30,064		3,667	129,738		129,738
Due to other funds				31,336			31,336		-
	179,853	16	66,496	70,271	-	5,310	321,946	361	258,416
OTHER NONCURRENT LIABILITIES	9,337	-	-	-	-	-	9,337	-	9,337
CURRENT LIABILITIES									
Current maturities of long-term debt	6,100	690	54,160	95,155		4,315	160,420		160,420
Accounts payable and accrued expenses	36,146	985	512	425	1,795	522	40,385	27,369	67,754
Due to Participants	19,744						19,744		19,744
Due to other funds		1,081					1,081		-
Due to other business units				357		1,105	1,462	2,264	-
	61,990	2,756	54,672	95,937	1,795	5,942	223,092	29,633	247,918
DEFERRED CREDITS									
Advances from Members and others								816	816
Other deferred credits		4,582				354	4,936	168	5,104
	-	4,582	-	-	-	354	4,936	984	5,920
TOTAL LIABILITIES	2,686,950	7,918	2,047,270	1,940,470	1,795	165,674	6,850,077	30,978	6,812,357
TOTAL FUND EQUITY AND LIABILITIES	$ 2,686,950	$ 7,918	$ 2,047,270	$ 1,940,470	$ 6,278	$ 144,719	$ 6,833,605	$ 37,405	$ 6,802,312

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

STATEMENTS OF OPERATIONS AND FUND EQUITY

For the year ended June 30, 2008 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2008 Combined Total
OPERATING REVENUES	$ 428,994	$ 2,962	$ -	$ -	$ 10,542	$ 12,568	$ 455,066	$ -	$ 455,066
OPERATING EXPENSES									
Nuclear fuel	35,873						35,873		35,873
Spent fuel disposal fee	9,036						9,036		9,036
Decommissioning	6,163					74	6,237		6,237
Depreciation and amortization	72,983	35			219	4,159	77,396		77,396
Operations and maintenance	161,079	2,068			12,125	3,734	179,006		179,006
Other power supply expense		697					697		697
Administrative and general	24,088	157				46	24,291		24,291
Generation tax	4,019	16				51	4,086		4,086
TOTAL OPERATING EXPENSES	313,241	2,973	-	-	12,344	8,064	336,622	-	336,622
NET OPERATING REVENUES (EXPENSES)	115,753	(11)	-	-	(1,802)	4,504	118,444	-	118,444
OTHER INCOME AND EXPENSE									
Non-operating revenues			105,706	93,764			199,470	61,540	199,894
Investment income	4,426	85	2,301	2,040	81	449	9,382	368	9,382
Interest expense and discount amortization	(121,464)	(74)	(105,617)	(93,664)		(7,870)	(328,689)		(328,689)
Plant preservation and termination costs			(2,166)	(2,140)			(4,306)		(4,306)
Depreciation and amortization			(6)				(6)	(2,039)	(6)
Decommissioning			(483)				(483)		(483)
Services to other business units								(59,445)	-
Other	1,285		265		2,321		3,871		3,871
TOTAL OTHER INCOME AND EXPENSES	(115,753)	11	-	-	2,402	(7,421)	(120,761)	424	(120,337)
NET REVENUES (EXPENSES)	-	-	-	-	600	(2,917)	(2,317)	424	(1,893)
Distribution and Contributions	-	-	-	-	2,500	(117)	2,383	(2,868)	(485)
Beginning Fund Equity	-	-	-	-	1,383	(17,921)	(16,538)	8,871	(7,667)
ENDING FUND EQUITY	$ -	$ -	$ -	$ -	$ 4,483	$ (20,955)	$ (16,472)	$ 6,427	$ (10,045)

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

STATEMENTS OF CASH FLOWS

For the year ended June 30, 2008 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2008 Combined Total
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES								
Operating revenue receipts	$ 330,971	$ 2,507	$ -	$ -	$ 5,912	$ 12,568	$ -	$ 351,958
Cash payments for operating expenses	(215,729)	(2,492)			(2,600)	(2,907)		(223,728)
Non-operating revenue receipts			155,413	176,032				331,445
Cash payments for preservation, termination expense			(1,625)	32				(1,593)
Cash payments for services							(2,408)	(2,408)
Net cash provided/(used) by operating and other activities	115,242	15	153,788	176,064	3,312	9,661	(2,408)	455,674
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	312,394		331,712	295,350				939,456
Refunded bond escrow requirement	(263,954)		(331,730)	(295,597)				(891,281)
Payment for bond issuance and financing costs	(1,889)	(20)	(2,664)	(2,593)	(1)	(193)		(7,360)
Payment for capital items	(35,741)	(1,615)			(158)	(47,535)	(669)	(85,718)
Receipts from sales of plant assets			1,356					1,356
Nuclear fuel acquisitions	(14,284)							(14,284)
Interest paid on revenue bonds	(115,423)	(70)	(94,979)	(73,716)		(7,435)		(291,623)
Principal paid on revenue bond maturities	(4,280)	(660)	(9,160)			(3,380)		(17,480)
Interest paid on Notes	(516)		(278)					(794)
Net cash provided/(used) by capital and related financing activities	(123,693)	(2,365)	(105,743)	(76,556)	(159)	(58,543)	(669)	(367,728)
CASH FLOWS FROM NON-CAPITAL FINANCE ACTIVITIES								
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(1,327,660)	(3,795)	(601,228)	(441,029)	(11,223)	(214,618)	(128,345)	(2,727,898)
Sales of investment securities	1,330,149	5,606	550,572	341,428	11,335	263,600	130,877	2,633,567
Interest on investments	4,311	118	2,300	1,936	88	2,033	464	11,250
Net cash provided/(used) by investing activities	6,800	1,929	(48,356)	(97,665)	200	51,015	2,996	(83,081)
NET INCREASE (DECREASE) IN CASH	(1,651)	(421)	(311)	1,843	3,353	2,133	(81)	4,865
CASH AT JUNE 30, 2007	78,403	430	1,358	1,560	53	7,259	1,956	91,019
CASH AT JUNE 30, 2008 (NOTE B)	$ 76,752	$ 9	$ 1,047	$ 3,403	$ 3,406	$ 9,392	$ 1,875	$ 95,884

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

STATEMENTS OF CASH FLOWS (CONT'D)

For the year ended June 30, 2008 (Dollars in Thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2008 Combined Total
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net operating revenues	$ 115,753	$ (11)	$ -	$ -	$ (1,802)	$ 4,504	$ -	$ 118,444
Adjustments to reconcile net operating revenues to cash provided by operating activities:								
Depreciation and amortization	106,981	25			86	4,145		111,237
Decommissioning	6,163					75		6,238
Other	1,935	1,636			2,350	44		5,965
Change in operating assets and liabilities:								
Deferred charges/costs in excess of billings	(98,023)	(22)						(98,045)
Accounts receivable	1,023	(233)			(245)			545
Materials and supplies	(7,612)							(7,612)
Prepaid and other assets	(67)				9	7		(51)
Due from/to other business units, funds and Participants	(6,163)	(1,988)			400	567		(7,184)
Accounts payable	(4,748)	608			14	512		(3,614)
Non-operating revenue receipts			155,413	176,032				331,445
Cash payments for preservation, termination expense			(1,625)	32				(1,593)
Cash payments for services							(2,408)	(2,408)
Receipts for grants/contributions					2,500	(193)		2,307
Net cash provided (used) by operating and other activities	$ 115,242	$ 15	$ 153,788	$ 176,064	$ 3,312	$ 9,661	$ (2,408)	$ 455,674

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

Energy Northwest
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. Membership consists of 19 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

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 Bonneville Power Administration (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 who 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 operates the Columbia Generating Station (Columbia), a 1,150 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 is in the initial phase of preparing an application to renew the license for an additional 20 years, thus continuing operations to 2043. Submittal of this application is anticipated in the second half of July 2009. The NRC license renewal project is expected to take 18 to 24 months. Costs to date on Columbia relicensing are $5.4 million.

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. Packwood is currently proceeding through the relicensing effort; the initial application package for the relicensing of Packwood was submitted to FERC on February 22, 2008. Costs incurred to date for relicensing are $3.4 million. The electric power produced by Packwood is sold to 12 Project Participant utilities which pay the costs of Packwood, including the debt service on the Packwood revenue bonds. The Packwood participants are obligated to pay annual costs of Packwood including debt service, whether or not Packwood is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of the bond resolution. Any revenues in excess of net funding is shared with the participants and disbursed by share percentage to each participant or, by participant decision, retained in the project and applied towards future costs. In 2002, Packwood and its participants entered into a Power Sales Agreement with Benton and Franklin PUDs to guarantee a specified level of power generation from the Packwood project (see Note E, "Security-Packwood Lake Hydroelectric Project").

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"). All funding requirements remain as net-billed obligations of Nuclear Projects Nos. 1 and 3. Energy Northwest wholly owns Nuclear Project No. 1. Energy Northwest is no longer responsible for site restoration costs for Nuclear Project No. 3 (see Note F, Commitments and Contingencies).

Energy Northwest also manages the Business Development Fund and the Nine Canyon Wind Project (Nine Canyon):

- The Business Development Fund was established in April 1997 to pursue and develop new energy related business opportunities.

- Nine Canyon 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 (FY) 2003 and Phase II was completed in FY 2004. Phase I and II combined capacity is approximately 63.7 MWe. Phase III was completed in FY 2008 and began commercial operation in May, adding an additional 14 wind turbines to the Nine Canyon Project and adding an aggregate capacity of 32.2 MWe. Total Phases I, II and III turbines at the Nine Canyon project are 63 and total capacity for Phases I, II and III is 95.9 MWe.

The Internal Service 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.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest applies Financial Accounting Standards Board (FASB) standards to the extent it does not conflict with Governmental Accounting Standards Board (GASB) standards. Accounts are maintained in accordance with the uniform system of accounts of the Federal Energy Regulatory Commission (FERC). Energy Northwest uses the full accrual basis of accounting where revenues are recognized when earned and expenses recognized when incurred. Revenues and expenses related to principal operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be non-operating revenues and expenses. 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 capital assets such as data processing equipment, and for payment and accounting of internal services, payroll, benefits, administrative and general expenses, and certain contracted services on a cost reimbursement basis. Certain assets in the Internal Service Fund are also owned by this Fund and operated for the benefit of other Projects. Depreciation relating to capital assets is charged to the appropriate business units based upon assets held by each Project.

Liabilities of the Internal Service Fund represent accrued payroll, 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 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 FY 2008 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 GASB Statement No. 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," Energy Northwest has elected to apply all FASB statements and interpretations, except for those that conflict with, or contradict, GASB pronouncements. Specifically, GASB No. 7, "Advance Refundings Resulting in Defeasance of Debt," and GASB No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities," conflict with Statement of Financial Accounting Standard (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." As such, the guidance under GASB 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 GAAP requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities, disclosures 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 that management considers 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.

During the normal construction phase of a capital facility, which historically has been defined as construction of a generation facility, Energy Northwest's policy is to capitalize all costs relating to the Project, including interest expense, related administrative and general expense, less any interest income earned. For financing not related to a capital facility, Energy Northwest analyzes the gross interest expense relating to the cost of the bond sale, taking into account interest earnings and draws for purchase or construction reimbursements for the purpose of analyzing impact to the recording of capitalized interest. Columbia is a net-billed business unit, therefore costs whether expense or capital, are reimbursed each year. However, if estimated costs are more than inconsequential, an adjustment is made to allocate capitalized interest to the appropriate plant account.

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 were recorded in FY 1995 and were 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, 2008, was as follows:

Nuclear Fuel

All expenditures related to the initial purchase of nuclear fuel for Columbia, including interest, were 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

UTILITY PLANT ACTIVITY (Dollars in Thousands)

	Beginning Balance	Increases	Decreases	Ending Balance
Columbia Generating Station				
Generation	$ 3,545,749	$ 1,353	$ -	$ 3,547,102
Decommissioning	32,469			32,469
Construction Work-in-Progress	26,999	25,540		52,539
Accumulated Depreciation and Decommissioning	(2,174,753)	(71,658)	-	(2,246,411)
UTILITY PLANT, net*	$ 1,430,464	$ (44,765)	$ -	$ 1,385,699
Packwood Lake Hydroelectric Project				
Generation	$ 13,098	$ 461	$ -	$ 13,559
Accumulated Depreciation	(12,492)	(25)	-	(12,517)
UTILITY PLANT, net	$ 606	$ 436	$ -	$ 1,042
Business Development				
Generation	$ 1,230	$ 204	$ (107)	$ 1,327
Accumulated Depreciation	(496)	(52)	-	(548)
UTILITY PLANT, net	$ 734	$ 152	$ (107)	$ 779
Nine Canyon Wind Project				
Generation	$ 73,819	$ 58,537	$ -	$ 132,356
Decommissioning	449	412	-	861
Construction Work-in-Progress	11,177	45,948	(57,125)	-
Accumulated Depreciation and Decommissioning	(16,041)	(4,178)	-	(20,219)
UTILITY PLANT, net	$ 69,404	$ 100,719	$ (57,125)	$ 112,998
Internal Service Fund				
Generation	$ 46,765	$ 321	$ -	$ 47,086
Accumulated Depreciation	(35,751)	(2,039)	-	(37,790)
UTILITY PLANT, net	$ 11,014	$ (1,718)	$ -	$ 9,296

*Does not include Nuclear Fuel Amount of $208 million, net of amortization.

assemblies in the reactor used in the production of energy and in the fuel pool for less than six months per FERC guidelines) is $97.0 million as of June 30, 2008, for Columbia.

The loaned fuel agreement associated with the FY 2007 revenue was completed in FY 2007. A new fuel lease agreement was entered into and is in effect through FY 2009. The agreement provides for an exchange of uranium oxide (U_3O_8) for an equivalent amount of uranium hexafluoride (UF_6) plus the cash value of conversion services which is estimated to be $13.9 million. Approximately $0.3 million of the cash value for conversion services is attributable to FY 2008 activity and the remainder attributable to FY 2009 conversion services.

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, currently, there is no known operational date established.

The current period operating expense for Columbia includes a $9.0 million charge from the DOE for future spent nuclear fuel storage and disposal in accordance with the Nuclear Waste Policy Act of 1982.

Energy Northwest has completed the Independent Spent Fuel Storage Installation (ISFSI) project, which is a temporary dry cask storage until the DOE completes its plan for a national repository. ISFSI will store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. Twelve casks were issued from the cask inventory account in FY 2008. Spent Fuel is transferred from the Spent Fuel pool to the ISFSI periodically to allow for future refuelings. Current period operating costs include $34.3 million for nuclear fuel and $1.6 million dry cask storage costs.

Restricted Assets

Separate restricted funds have been established for each business unit, in accordance with Project bond resolutions, related agreements or state law. The assets held in these funds are restricted for specific uses including construction, debt service, capital additions and fuel purchases, extraordinary operation and maintenance costs, termination, decommissioning, hazardous waste disposal, operating reserves, financing, long-term disability and workers' compensation claims.

Long-Term Receivables

Long-term receivables include an estimate of future discounts for certain goods and services to be provided to Columbia. These amounts are the result of a litigation settlement and subsequent revisions of that settlement.

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 unit's account. Accounts and other receivables specific to each business unit are recorded in the residing business unit.

Asset Retirement Obligation

Energy Northwest adopted SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long Lived Asset," 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 for Asset Retirement Obligations).

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 2007.

Energy Northwest's current estimate of Columbia's decommissioning costs in 2007 dollars is $573.2 million (Columbia-$570.0 million and ISFSI-$3.2 million). This estimate, which is updated biannually, 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 by 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 costs is $80.6 million in constant dollars (based on the 2007 Study) and is updated biannually along with the decommissioning estimate.

Both decommissioning and site restoration estimates (based on 2007 Study) 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, 2008, totaled approximately $121.6 million and $17.2 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; the balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet. Energy Northwest established a second decommissioning and site restoration plan for the ISFSI. Beginning in FY 2003, an annual contribution is made to the Energy Northwest Decommissioning Fund. These contributions are held by Energy Northwest and not held in trust by BPA. The fair market value of cash and investments as of June 30, 2008 is $0.5 million. These contributions will occur through FY 2029; cash payments will begin for decommissioning and site restoration in FY 2025 with equal installments for five years totaling $2.06 million.

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 which Energy Northwest has determined to not be materially different from the effective interest method of bond accounting.

In accordance with GASB 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 (less than one year) of revenue bonds payable from restricted assets are reflected as current maturities. Debt with maturities greater than one year is reflected as Long-Term Debt.

Accounts Payable and Accrued Expenses

Liabilities - Payable From Restricted Assets-Columbia includes $113.0 million for decommissioning and site restoration. Nuclear Project No. 1

includes \$14.3 million for decommissioning and site restoration. Nine Canyon includes \$1.1 million for decommissioning and site restoration. The other large amount of payables from restricted assets relate to accrued interest payable. There was \$129.7 million accrued amongst the five business units (none for the Internal Service Fund) for this item.

Current Liabilities - There is \$65.3 million in current maturities of long-term debt for Columbia, Unit 1, Nine Canyon and Packwood. Columbia has \$19.7 million in liabilities to its participants. Internal Service Fund accounts payable and accrued expenses include \$5.1 million for payroll and related benefits, \$17.0 million for compensated absences, and \$5.2 million for outstanding warrants, taxes, and retention withheld. Other business unit accrued costs accounted for the other \$40.7 million and represents general business unit activity.

Other Non Current Liabilities - \$9.3 million is recorded for the Columbia deferred cask liability which relates to the storage and disposal of spent fuel.

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.

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, and Due To/From Participants, funds, and other business units. The fair values of investments (see Note C, Cash and Investments) and revenue bonds payable (see Note E, Long-Term Debt) have been estimated based on quoted market prices for such instruments or on the fair market 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 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 DOE, Renewable Energy Performance Incentive (REPI) payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI bill. 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. Nine Canyon recorded a receivable for the applied REPI funding in the amount of \$0.7 million for FY 2008, representing its share of funded amounts. The payment stream from Nine Canyon participants and the REPI receipts were projected to cover the total costs over the purchase agreement. Permanent shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project. The rate increases in the billing to the Nine Canyon participants in order to cover total Project costs occurred in FY 2008 and are projected out to the 2030 proposed project end date.

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, Long-Term Debt, "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.

Interest Risk

Energy Northwest's investment policy limits investments to those with maturities of one year or less, or as designated in specific bond resolutions.

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 but are classified as available for sale investments.

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. Safekeeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest business units.

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, 2008, 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:

AVAILABLE-FOR-SALE-INVESTMENTS (Dollars in Thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia Generating Station	$ 92,855	$ 1	$ (144)	$ 92,712
Packwood Lake Hydroelectric Project	749	-	-	749
Nuclear Project No. 1	114,446	-	(11)	114,435
Nuclear Project No. 3	143,029	-	(14)	143,015
Business Development Fund	960	-	-	960
Internal Service Fund	24,673	1	(28)	24,646
Nine Canyon Wind Project	18,387	-	(13)	18,374

(1) All investments are in U.S. Government Agencies with the exception of Packwood which holds only U.S. Government Treasury Bills.

(2) All investments have maturities of less than one year.

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. The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to: Department of Retirement Systems, Communications Unit, P.O. Box 48380, Olympia, WA 98504-8380. The following disclosures are made pursuant to GASB Statement 27, "Accounting for Pensions by State and Local Government Employers."

Any information obtained from the DRS is the responsibility of the State of Washington. PricewaterhouseCoopers LLP (PwC), independent auditors for Energy Northwest, has not audited or examined any of the information available from the DRS; accordingly, PwC does not express an opinion or any other form of assurance with respect thereto.

Public Employee's Retirement System (PERS) Plans 1, 2, and 3 Plan Description

PERS is a cost-sharing multiple-employer retirement system comprised of three separate plans for membership purposes: Plans 1 and 2 are defined benefit plans and Plan 3 is a defined benefit plan with a defined contribution component.

Membership in the system includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts (other than judges currently in a judicial retirement system); employees of legislative committees; community and technical colleges, college and university employees not participating in national higher education retirement programs; judges of district and municipal courts; and employees of local governments.

PERS participants who joined the system by September 30, 1977 are Plan 1 members. Those who joined on or after October 1, 1977 and by either, February 28, 2002 for state and higher education employees, or August 31, 2002 for local government employees, are Plan 2 members 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 irrevocable option of choosing membership in either PERS Plan 2 or PERS Plan 3. The option must be exercised within 90 days of employment. An employee is reported in Plan 2 until a choice is made. Employees who fail to choose within 90 days default to PERS Plan 3.

PERS defined benefit retirement benefits are financed from a combination of investment earnings and employer and employee contributions. PERS retirement benefit provisions are established in state statute and may be amended only by the State Legislature.

Plan 1 members are vested after the completion of five years of eligible service. Plan 1 members are eligible for retirement at any age after 30 years of service, or at the age of 60 with five years of service, or at the age of 55 with 25 years of service. The annual benefit is two percent of the average final compensation per year of service, capped at 60 percent. The average final compensation is based on the greatest compensation during any 24 eligible consecutive compensation months. Plan 1 retirements from inactive status prior to the age of 65 may receive actuarially reduced benefits. The benefit is actuarially reduced to reflect the choice of a survivor option. A cost-of living allowance (COLA) is granted at age 66 based upon years of service times the COLA amount, increased by three percent annually. Plan 1 members may also elect to receive an additional COLA amount (indexed to the Seattle Consumer Price Index), capped at three percent annually. To offset the cost of this annual adjustment, the benefit is reduced.

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

Plan 3 has a dual benefit structure. Employer contributions finance a defined benefit component, and member contributions finance a defined contribution component. The defined benefit portion provides a benefit calculated at one percent of the average final compensation per year of service. The average final compensation is based on the greatest compensation during any eligible consecutive 60-month period. Effective June 7, 2006, Plan 3 members are vested in the defined benefit portion of their plan after ten years of service; or after five years of service, if twelve months of that service are earned after age 44; or after five service credit years earned in PERS Plan 2 prior to June 1, 2003. Plan 3 members are immediately vested in the defined contribution portion of their plan. Vested Plan 3 members are eligible to retire with full benefits at age 65, or at age 55 with 10 years of service. Retirements prior to the age of 65 receive reduced benefits. If retirement is at age 55 or older with at least 30 years of service, a three percent per year reduction applies; otherwise an actuarial reduction will apply. The benefit is also actuarially reduced to reflect the choice of a survivor option. There is no cap on years of service credit, and Plan 3 provides the same cost-of-living allowance as Plan 2.

The defined contribution portion can be distributed in accordance with an option selected by the member, either as a lump sum or pursuant to other options authorized by the Employee Retirement Benefits Board.

There are 1,188 participating employers in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of September 30, 2006:

Retirees and Beneficiaries Receiving Benefits	70,201
Terminated Plan Members Entitled to but not yet Receiving Benefits	25,610
Active Plan Members Vested	105,215
Active Plan Members Non-vested	49,812
Total	**250,838**

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates, Plan 2 employer and employee contribution rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at 6 percent for state agencies and local government unit employees, and at 7.5 percent for state government elected officials. The employer and employee contribution rates for Plan 2 and the employer contribution rate for Plan 3 are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. All employers are required to contribute at the level established by the Legislature. Under PERS Plan 3, employer contributions finance the defined benefit portion of the plan, and member contributions finance the defined contribution portion. The Employee Retirement Benefits Board sets Plan 3 employee contribution rates. Six rate options are available ranging from 5 to 15 percent; two of the options are graduated rates dependent on the employee's age. The methods used to determine the contribution requirements are established under state statute in accordance with chapters 41.40 and 41.45 RCW.

The required contribution rates expressed as a percentage of current year covered payroll, as of December 31, 2007, were as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	6.13%**	6.13%**	6.13%***
Employee	6.00%****	4.15%****	*****

*The employer rates include the employer administrative expense fee currently set at 0.16%. This rate change was effective September 1, 2007, previous rate was 0.18%.
**The employer rate for state elected officials is 9.12% for Plan 1 and 6.13% for Plan 2 and Plan 3.
***Plan 3 defined benefit portion only.
****The employee rate for state elected officials is 7.50% for Plan 1 and 4.15% for Plan 2.
*****Variable from 5.0% minimum to 15.0% maximum based on rate selected by the PERS 3 member.

Both Energy Northwest and the employees make the required contributions. The required employer contribution increased July 1, 2007 from 5.46 percent for all plans to 6.12 percent and then again on September 1, 2007 to the current level of 6.13 percent. For FY 2006 and FY 2007 the rates ranged from 2.44 percent to 5.46 percent. Energy Northwest's required contributions for the years ended June 30 was:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
2008	$ 201,971	$ 4,313,031	$ 1,702,720
2007	$ 174,813	$ 3,235,922	$ 1,269,321
2006	$ 107,096	$ 1,458,655	$ 564,242

In addition to the pension benefits available through PERS, Energy Northwest offered post-employment life insurance benefits to retirees who were eligible to receive pensions under PERS Plan 1, Plan 2 and Plan 3. There are 83 retirees that remain participants in the insurance program. 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 retirees increased in January of 2008 from $2.33 to $2.82 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. The rate increase was not passed along to these retirees as the original resolution did not address future changes to these grandfathered participants. Premiums are paid to the insurer on a current period basis.

The liability for the actuarial value of estimated future premiums, net of retiree contributions is determined annually and was $0.8 million at June 30, 2008.

During FY 2008, pension costs for Energy Northwest employees and post-employment life insurance benefit costs for retirees were calculated and allocated to each business unit based on direct labor dollars. This allocation basis resulted in the following percentages by business unit for FY 2008 for this and other allocated costs; Columbia at 92 percent, Business Development at 7 percent, and Project 1, Nine Canyon, Packwood and Project 3 receiving the residual amount of one percent.

401(k) and 457 Plan Deferred Compensation Plan

Energy Northwest provides a 401(k) Deferred Compensation Plan (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. Participants are immediately vested in their contributions and direct the investment of their contribution. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations. For the 401(k) Plan, Energy Northwest may elect to make an employer matching contribution for each of its employees who are participants during the Plan Year. The amount of such an Employer match shall be 50 percent of the maximum salary deferral percentage. During FY 2008 Energy Northwest contributed $2.0 million 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 (the "Electric Revenue Bonds") 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. Nine Canyon's bonds were authorized by the following resolutions: Resolution No. 1214 2001 Bonds, Resolution No. 1299 2003 Bonds, Resolution No. 1376 2005 Bonds and Resolution No.1482 the 2006 Bonds. The Packwood Bonds were authorized by Resolution 325 for the 1962 Bonds and Resolution 328 for the 1965 Bonds.

During the year ended June 30, 2008, Energy Northwest issued, for Nuclear Projects No. 1 and 3, and Columbia, the Series 2008-A Bonds, Series 2008-B Bonds, Series 2008-D Bonds, and Series 2008-E Bonds. The Series 2008-C Bonds were issued for Columbia, and the 2008-F Bonds were issued for Project 3. The Series 2008-A, 2008-B, 2008-C, 2008-D, and 2008-E Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are fixed rate bonds with a weighted average coupon interest rate ranging from 4.15 percent to 5.85 percent. The Series 2008-F Bonds issued for Nuclear Project No. 3 are Variable Rate Bonds with a weekly rate reset. These transactions resulted in a net-loss for accounting purposes of $10.55 million. According to GASB No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities," gains and losses on the refundings are deferred and amortized over the remaining life of the old debt or the new debt, whichever is shorter. However, in accordance with GASB 7, "Advance Refundings Resulting in Defeasance of Debt," an economic gain of $15.82 million was recognized, based on the present value of debt service comparison.

The Series 2008-A Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are tax exempt fixed-rate bonds that created savings based on improved interest rates.

The Series 2008-B Bonds, issued for Nuclear Project No. 1, Nuclear Project No. 3 and Columbia are taxable fixed-rate bonds for the purpose of paying costs relating to the issuance of the Series 2008-A, Series 2008-B, and Series 2008-C Bonds, as well as certain costs relating to the refunding of certain outstanding bonds.

The Series 2008-C Bonds issued for Columbia are tax exempt fixed-rate bonds to finance a portion of the cost of certain capital improvements at Columbia.

The Series 2008-D Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are tax exempt fixed-rate bonds that created savings based on improved interest rates.

The Series 2008-E Bonds issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are taxable fixed-rate bonds for the purpose of paying costs relating to the issuance of the Series 2008-D, Series 2008-E, and Series 2008-F Bonds, as well as certain costs relating to the refunding of certain outstanding bonds.

The Series 2008-F Bonds issued for Nuclear Project No. 3 are variable-rate bonds that created savings based on improved interest rates.

Nuclear Projects Nos. 1 and 3 have long term debt that contains variable rate interest. These rates are set periodically through a weekly rate reset. These rates ranged from 1.080 percent to 7.000 percent during FY 2008.

The Bond Proceeds, Weighted Average Coupon Interest Rates, Net Accounting Loss, Economic Gain, and total defeased bonds for 2008-A, 2008-B, 2008-C, 2008-D, 2008-E, and 2008-F are presented in the following tables:

Bond Proceeds ($ in millions)

	Project 1	Columbia	Project 3	Total
2008A	$ 250.23	$ 120.18	$ 15.00	$ 385.41
2008B	2.16	14.85	0.11	17.12
2008C	-	38.37	-	38.37
2008D	77.23	135.45	68.93	281.61
2008E	2.10	3.55	2.49	8.14
2008F	-	-	208.83	208.83
Total	$ 331.72	$ 312.40	$ 295.36	$ 939.48

Total Defeased ($ in millions)

	Project 1	Columbia	Project 3	Total
2008A	$ 250.24	$ 120.19	$ 15.00	$ 385.43
2008B	-	-	-	-
2008C	-	-	-	-
2008D	77.23	135.45	68.93	281.61
2008E	-	-	-	-
2008F	-	-	208.83	208.83
Total	$ 327.47	$ 255.64	$ 292.76	$ 875.87

Weighted Average Coupon Interest Rate for Refunded Bonds

	2008A	2008B	2008C	2008D	2008E	2008F
Total	5.56%*	-	-	5.08%	-	**

* The 2008A issue refunded variable rate bonds that are not included.
** The 2008F bond issue refunded variable rate bonds.

Weighted Average Coupon Interest Rate for New Bonds

	2008A	2008B	2008C	2008D	2008E	2008F
Total	5.11%	5.85%	5.07%	5.00%	4.15%	*

* The 2008F series bonds are variable rate bonds with weekly rate resets.

Net Accounting Loss ($ in millions)

	Project 1	Columbia	Project 3	Total
2008A	$ (0.88)	$ (2.22)	$ (0.26)	$ (3.36)
2008B	2.14	2.80	0.10	5.04
2008C	-	-	-	-
2008D	0.30	(0.26)	0.55	0.59
2008E	2.08	3.52	1.72	7.32
2008F	-	-	0.96	0.96
Total	$ 3.64	$ 3.84	$ 3.07	$ 10.55

Energy Northwest did not issue or refund any bonds associated with Packwood or Nine Canyon for FY 2008. 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 statements No. 7 and 23. Including the FY 2008 defeasements, $327.5 million, $292.7 million, and $255.6 million of defeased bonds were not called or had not matured at June 30, 2008, for Nuclear Projects Nos. 1 and 3, and Columbia respectively.

Outstanding principal on revenue and refunding bonds for the various business units as of June 30, 2008, and future debt service requirements for these bonds are presented in the following tables:

OUTSTANDING LONG-TERM DEBT

As of June 30, 2008 (Dollars in Thousands)

Columbia Revenue and Refunding Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1992A	6.30	7-1-2012	$ 50,000
1994A	(A)	7-1-2009	4,776
	5.40	7-1-2012	100,200
			104,976
1998A	5.75	7-1-2009	20,625
2001A	5.00-5.50	7-1-13/2017	186,600
2001B	5.50	7-1-2018	48,000
2002A	5.20-5.75	7-1-17/2018	157,260
2002B	5.35-6.00	7-1-2018	123,815
2003A	5.50	7-1-10/2015	132,970
2003B	4.15	7-1-2009	4,530
2003F	5.00-5.25	7-1-08/2018	38,740
2004A	5.25	7-1-09/2018	324,350
2004B	5.50	7-1-2013	12,715
2004C	5.25	7-1-08/2018	24,930
2005A	5.00	7-1-15/2018	114,985
2005B	4.11	7-1-2008	1,600
2005C	4.34-4.74	7-1-09/2015	91,890
2006A	5.00	7-1-20/2024	434,210
2006B	5.23	7-1-2011	4,420
2006C	5.00	7-1-20/2024	62,200
2006D	5.80	7-1-2023	3,425
2007A	5.00	7-1-13/2018	77,575
2007B	5.07-5.33	7-1-12/2021	10,665
2007D	5.00	7-1-21/2024	35,080
2008A	5.00-5.25	7-1-14/2018	110,935
2008B	3.60-5.95	7-1-09/2021	14,850
2008C	5.00-5.25	7-1-21/2024	37,240
2008D	5.00	7-1-10/2012	127,510
2008E	4.15	7-1-2009	3,545
Compound interest bonds accretion			6,224
Revenue bonds payable			$ 2,365,865
Estimated fair value at June 30, 2008			$ 2,491,535 (B)

(A) Compound Interest Bonds
(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

Nuclear Project No.1 Refunding Revenue Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1989B	7.125	7-1-2016	$ 41,070
1990B	7.25	7-1-2009	3,590
1993B	7.00	7-1-08/2009	15,090
1993C	5.20	7-1-2008	1,985
1996A	6.00	7-1-2008	40,050
1996C	6.00	7-1-2009	8,445
1998A	5.75	7-1-2009	3,750
2001A	4.50-5.50	7-1-10/2013	76,560
2002A	5.50-5.75	7-1-13/2017	248,485
2002B	6.00	7-1-2017	101,950
2003A	5.50	7-1-13/2017	241,455
2003B	4.06	7-1-2009	18,210
2004A	5.25	7-1-2013	62,485
2004B	5.50	7-1-2013	1,135
2005A	5.00	7-1-13/2015	72,175
2005B	4.11	7-1-2008	925
2006A	5.00	7-1-09/2017	308,315
2007A	5.00	7-1-13/2017	51,730
2007B	5.07-5.10	7-1-12/2013	6,740
2007C	5.00	7-1-13/2017	219,020
2008A	5.00-5.25	7-1-13/2017	230,535
2008B	3.60	7-1-2009	2,155
2008D	5.00	7-1-13/2017	72,000
2008E	4.15	7-1-2009	2,095
1993-1A-1	VARIABLE		36,120
1993-1A-2	VARIABLE		39,070
1993-1A-3	VARIABLE		12,810
Revenue bonds payable			$ 1,917,950
Estimated fair value at June 30, 2008			$ 2,040,962 (B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

OUTSTANDING LONG-TERM DEBT (CONT'D)

As of June 30, 2008 (Dollars in Thousands)

Nuclear Project No.3 Refunding Revenue Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	
1989A	(A)	7-1-08/2014	$ 11,112	
1989B	(A)	7-1-08/2014	37,537	
	7.125	7-1-2016	76,145	
			113,682	
1990B	(A)	7-1-08/2010	8,225	
1993B	5.65-7.00	7-1-08/2009	23,460	
1993C	7.50	7-1-2008	14,150	
	(A)	7-1-13/2018	23,963	
			38,113	
1997A	6.00	7-1-2009	13,585	
2001A	5.50	7-1-10/2018	151,380	
2001B	5.50	7-1-2018	10,675	(C)
2002B	6.00	7-1-2016	75,360	
2003A	5.50	7-1-11/2017	241,915	
2003B	4.15	7-1-2009	21,575	
2004A	5.25	7-1-14/2016	83,835	
2004B	5.50	7-1-2013	1,515	
2005A	5.00	7-1-13/2015	129,265	
2005B	4.11	7-1-2008	1,060	
2006A	5.00	7-1-08/2018	54,760	
2006B	5.21	7-1-2008	525	
2007A	4.50-5.00	7-1-13/2018	84,465	
2007B	5.07	7-1-2012	1,725	
2007C	5.00	7-1-12/2018	61,085	
2008A	5.25	7-1-2018	13,790	
2008B	3.70	7-1-2010	110	
2008D	5.00	7-1-09/2017	64,295	
2008E	4.15	7-1-2009	2,485	
1993-3A-3	VARIABLE		18,205	
1998-3A	VARIABLE		11,130	
2003D-1	VARIABLE		100,665	
2003E	VARIABLE		98,025	
2008-F1	VARIABLE		104,415	
2008-F2	VARIABLE		104,415	
Compound interest bonds accretion			261,328	
Revenue bonds payable			$ 1,906,180	
Estimated fair value at June 30, 2008			$ 1,944,054	(B)

(A) Compound Interest Bonds
(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.
(C) Auction Rate Certificates that will have a rate of 5.50% through 7/1/2010 and a variable rate thereafter until 7/1/2018.

Packwood Lake Hydroelectric Project Refunding Revenue Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	
1962	3.625	3-1-09/2010	$ 741	
1965	3.75	3-1-09/2012	500	
Revenue bonds payable			$ 1,241	
Estimated fair value at June 30, 2008			$ 1,260	(B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

Nine Canyon Wind Project Refunding Revenue Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	
2001A	4.95	7-1-2008	$ 1,760	
2001B	4.95	7-1-2008	705	
2003	3.75-5.00	7-1-08/2023	19,335	
2005	4.00-5.00	7-1-08/2023	61,540	
2006	4.50-5.00	7-1-10/2030	69,410	
Revenue bonds payable			$ 152,750	
Estimated fair value at June 30, 2008			$ 156,373	(B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

Total Bonds Payable	$ 6,343,986
Estimated fair value at June 30, 2008	$ 6,634,184

DEBT SERVICE REQUIREMENTS

As of June 30, 2008 (Dollars in Thousands)

Columbia Generating Station

Fiscal Year	Principal	Interest	Total
6/30/2008 Balance*	$ 6,100	$ 49,251	$ 55,351
2009	117,176	131,666	248,842
2010	156,795	117,050	273,845
2011	94,395	108,919	203,314
2012	266,810	104,134	370,944
2013	69,090	89,686	158,776
2014-2017	560,800	301,710	862,510
2018-2022	833,215	160,380	993,595
2023-2024	255,260	19,355	274,615
Adjustment **	6,224	(6,224)	-
	$ 2,365,865	$ 1,075,927	$ 3,441,792

* Principal and interest due July 1, 2008.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

Nuclear Project No. 1

Fiscal Year	Principal	Interest	Total
6/30/2008 Balance*	$ 54,160	$ 41,040	$ 95,200
2009	92,045	100,721	192,766
2010	83,890	92,865	176,755
2011	92,550	88,783	181,333
2012	91,140	84,275	175,415
2013	313,435	79,663	393,098
2014-2017	1,190,730	165,357	1,356,087
	$ 1,917,950	$ 652,704	$ 2,570,654

* Principal and interest due July 1, 2008.

Nuclear Project No. 3

Fiscal Year	Principal	Interest	Total
6/30/2008 Balance*	$ 64,425	$ 28,763	$ 93,188
2009	65,328	107,433	172,761
2010	35,232	104,970	140,202
2011	83,539	95,710	179,249
2012	70,606	92,081	162,687
2013	133,440	96,528	229,968
2014-2017	801,180	246,570	1,047,750
2018	391,101	25,035	416,136
Adjustment **	261,328	(261,328)	-
	$ 1,906,179	$ 535,762	$2,441,941

* Principal and interest due July 1, 2008.

** 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
6/30/2008 Balance***	$ 690	$ 46	$ 736
2009	336	20	356
2010	150	8	158
2011	65	2	67
	$ 1,241	$ 76	$ 1,317

*** Principal and interest due March 1, 2009.

Nine Canyon Wind Project

Fiscal Year	Principal	Interest	Total
6/30/2008 Balance*	$ 4,315	$ 3,667	$ 7,982
2009	3,705	7,139	10,844
2010	3,965	6,963	10,928
2011	4,260	6,774	11,034
2012	4,575	6,570	11,145
2013	6,930	6,351	13,281
2014-2017	31,310	21,873	53,183
2018-2022	48,495	18,134	66,629
2023-2030	45,195	8,692	53,887
	$ 152,750	$ 86,163	$ 238,913

* Principal and interest due July 1, 2008.

Security - Nuclear Projects Nos. 1 and 3 and Columbia

Project participants have purchased all of the capability of Nuclear Projects Nos. 1 and 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 a pro rata share of the total annual costs of the respective Projects, including debt service on bonds relating to each business unit. BPA is then obligated to reduce amounts from participants under BPA power sales agreements

by the same amount. 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 FY 1999 (see Note F, Commitments and Contingencies).

Security - Packwood Lake Hydroelectric Project

Energy Northwest, Benton County PUD and Franklin County PUD have signed a Power Sales agreement, as amended, which extends the period through October 1, 2008. The agreement became effective November 1, 2002. Benton and Franklin County PUDs agree to pay Energy Northwest in exchange for the total output of electric capacity and energy delivered from the Packwood Generation Project. In addition, the Project is required to supply a specified amount of power to Benton and Franklin County PUDs. If power production does not supply the required amount of power, the Project is required to provide any shortfall by purchasing power on the open market which resulted in $0.7 million of purchased power in FY 2008. 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 also share project revenue to the extent that the amounts exceed project costs.

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 the fact 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 SRP 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 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 SRP to transfer the real and personal property at the site of Nuclear Project No. 3. The SRP also agreed to assume regulatory responsibility for site restoration. Therefore, Energy Northwest is no longer responsible to the State of Washington and 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 EFSEC, and a lease agreement with the 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 FY 2003. This submittal was used to calculate the 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 a potential mandate of an additional 25 percent step-up possible for a maximum 9.23 percent. As of June 30, 2008 (unaudited), NoaNet has $18.4 million in network revenue bonds outstanding. 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 (based on step-up potential) that the Business Development Fund could be required to pay is $1.7 million. It is important to note that 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 FY 2008 the Business Development Fund contributed $223k 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 $11.5 million as of June 30, 2008. Future equity contributions, if any, will be treated the same until NoaNet has a positive equity position. Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, NoaNet Headquarters, 5802 Overlook Ave. NE, Tacoma, WA 98422.

Any information obtained from NoaNet is the responsibility of NoaNet. PwC has not audited or examined any information available from Noanet; accordingly, PwC does not express an opinion or any other form of assurance with respect thereto.

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.

Federal law under the Price Anderson Act currently limits public liability claims from a nuclear incident. As of June 30, 2008, the current limit was $10.8 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. As required by law, Energy Northwest has purchased the maximum commercial insurance available of $300 million, which is the primary layer of protection. The remaining balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims that exceed the individual licensee's primary insurance layer. The current maximum deferred premium for each nuclear incident is $100.59 million per reactor, but not more than $15 million per reactor may be charged in any one year for each incident. 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 $2.75 billion. The deductible for this coverage is $5.0 million per occurrence.

NOTE G - ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

Energy Northwest adopted SFAS No. 143 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 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, and is 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 billings in 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, Nuclear Project No. 1 and Nine Canyon. Decommissioning and site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the NRC regulations and site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the EFSEC and a lease agreement with the DOE (see Notes B and F). Additionally, there are separate lease agreements for land located at Nine Canyon. Leases at these locations are considered operating leases and expenses were $750k for Columbia, $7.6k for Nuclear Project No. 1 and $476k for the Nine Canyon project.

As of June 30, 2008, Columbia has a capital decommissioning net asset value of $18.1 million and an accumulated liability of $111.3 million for the generating plant and a net asset value of $1.2 million and an accumulated liability of $1.7 million for the ISFSI.

An adjustment was made in FY 2008 for

Nuclear Project No. 1 to account for costs incurred for decommissioning and site restoration. Costs incurred in FY 2008 of $136k combined with the current year accretion expense of $0.71 million and revision in future restoration estimates of $(0.10) million resulted in a small increase to the ARO of $0.48 million. Nuclear Project No. 1 has a capital decommissioning net asset value of $0 and an accumulated liability of $14.3 million.

Under the current agreement, Nine Canyon has the obligation to remove the generation facilities upon expiration of the lease agreement if requested by the lessors. The Nine Canyon Wind Project recorded the related original ARO in FY 2003 for Phase I and II. Phase III began commercial operation in FY 2008 and the original ARO was adjusted to reflect the change in scenario for the retirement obligation, with current lease agreements reflecting a 2030 expiration date. As of June 30, 2008, Nine Canyon has a capital decommissioning net asset value of $0.9 million and an accumulated liability of $1.1 million.

Packwood's obligation has not been calculated because the time frame and extent of the obligation was considered under this statement as indeterminate. As a result, no reasonable estimate of the ARO obligation can be made. An ARO will be required to be recorded if circumstances change. Management believes that these assets will be used in utility operations for the foreseeable future.

The following table describes the changes to Energy Northwest's ARO liabilities for the year ended June 30, 2008:

Asset Retirement Obligation
(Millions of Dollars)

Columbia Generating Station		
Balance at June 30, 2007	$	105.74
Current year accretion expense		5.53
ARO at June 30, 2008	$	111.27

ISFSI		
Balance at June 30, 2007	$	1.58
Current year accretion expense		0.09
ARO at June 30, 2008	$	1.67

Nuclear Project No. 1		
Balance at June 30, 2007	$	13.79
Less: Restoration costs incurred		(0.14)
Current year accretion expense		0.71
Revision in future restoration estimates		(0.10)
ARO at June 30, 2008	$	14.27

Nine Canyon Wind Project		
Balance at June 30, 2007	$	0.60
Current year accretion expense		0.04
Revision in future restoration estimates		0.41
ARO at June 30, 2008	$	1.05

CURRENT DEBT RATINGS (unaudited)

Energy Northwest (Long-Term)	Net-Billed Rating	Nine Canyon Rating
Fitch, Inc.	AA-	A-
Moodys Investors Service, Inc. (Moodys)	Aaa	A3
Standard and Poor's Ratings Services (S & P)	AA-	A-

Variable Rate Debt	S&P	FITCH	MOODYS
Letter of Credit Banks			
Bank of America			
Long-Term	AA+		Aaa
Short-Term	A-1+		VMIG-1
JPMorgan Chase Bank			
Long-Term	AA-	AA	Aaa
Short-Term	A-1+	F1+	VMIG-1
VRDN's			
Liquidity Provider			
Dexia			
Long-Term	AA-	AA-	Aaa
Short-Term	A-1+	F1+	VMIG-1
Bond Insurance (Long-Term)			
Financial Security Assurance	AAA	AAA	Aaa

This report is dedicated to Vera Claussen, our long time friend, Energy Northwest Board Member, and strong supporter of public power.

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL

Energy Northwest

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Merrill Lynch, Pierce, Fenner and Smith Incorporated

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 [$49,420,000/$204,110,000/$117,025,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] [Refunding] Bonds, Series 2009-A, Series 2009-B (Taxable) [and Series 2009-C] (the "2009 Bonds"). The 2009 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue 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 Resolution adopted by the Executive Board on April 2, 2009 (the "Supplemental Resolution"). The Electric Revenue 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 2009 Bonds are subject to redemption in the manner and upon the terms and conditions set forth in the Bond Resolutions. The 2009 Bonds rank junior as to security and payment to bonds issued and outstanding under the Prior Lien Resolution. The 2009 Bonds rank equally as to security and payment with all other Parity Debt.

Regarding questions of fact material to our opinion, we have relied on representations of Energy Northwest in the Bond Resolutions and in the certified proceedings and on other certifications of public officials and others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

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 2009 Bonds and apply the proceeds of the 2009 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 2009 Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2009 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 2009 Bonds are payable solely from the revenues and other amounts pledged to such

payment under the Bond Resolutions. The 2009 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 2009 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, and we express no opinion regarding the enforceability of provisions in the Bond Resolutions that provide for rights of indemnification.

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,

FOSTER PEPPER PLLC

PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL

Energy Northwest

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Merrill Lynch, Pierce, Fenner and Smith Incorporated

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 [$49,420,000/$204,110,000/$117,025,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] [Refunding] Bonds, Series 2009-A, Series 2009-B (Taxable) [and Series 2009-C] (the "2009 Bonds"). The 2009 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue 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 April 2, 2009 (the "Supplemental Resolution"). The Electric Revenue 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 2009 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 Electric Revenue Bond 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 and 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 provides 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 Agreements 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,

FOSTER PEPPER PLLC

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PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$48,905,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-A
$116,425,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A
$116,055,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-A
$515,000 Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)
$18,515,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable)
$970,000 Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable)
$69,170,000 Columbia Generating Station Electric Revenue Bonds, Series 2009-C

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $48,905,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2009-A (the "Project 1 2009-A Bonds"), $116,425,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2009-A (the "Columbia 2009-A Bonds"), $116,055,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2009-A (the "Project 3 2009-A Bonds," and together with the Project 1 2009-A Bonds and the Columbia 2009-A Bonds, the "Series 2009-A Bonds"), $515,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2009-B (Taxable) (the "Project 1 2009-B Taxable Bonds"), $18,515,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2009-B (Taxable) (the "Columbia 2009-B Taxable Bonds"), $970,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2009-B (Taxable) (the "Project 3 2009-B Taxable Bonds," and together with the Project 1 2009-B Taxable Bonds and the Columbia 2009-B Taxable Bonds, the "Series 2009-B Taxable Bonds") and $69,170,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2009-C (the "Columbia 2009-C Bonds" or the "Series 2009-C Bonds"). The Project 1 2009-A Bonds and the Project 1 2009-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 April 2, 2009 (the "Project 1 Resolution"). The Columbia 2009-A Bonds, the Columbia 2009-B Taxable Bonds and the Columbia 2009-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 April 2, 2009 (the "Columbia Resolution"). The Project 3 2009-A Bonds and the Project 3 2009-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 April 2, 2009 (the "Project 3 Resolution," and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Resolutions provide that the Series 2009-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest. The Resolutions provide that the Series 2009-B Taxable Bonds are being issued for the purpose of paying certain costs of issuance and other refunding costs relating to the Series 2009-A Bonds, the Series 2009-B Taxable Bonds and the Series 2009-C Bonds, paying a portion of operating costs of Columbia, and paying a portion of the costs of certain capital improvements to the Columbia Generating Station. The Resolutions provide that the Series 2009-C Bonds are being issued for the purpose of financing a portion of the costs of certain capital improvements at the Columbia Generating Station and paying costs of issuance of the Columbia 2009-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 Foster Pepper PLLC, 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.

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. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the Series 2009-A Bonds, Series 2009-B Taxable Bonds and Series 2009-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 2009-A Bonds or Series 2009-C Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights under the Series 2009-A Bonds, the Series 2009-C Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to the 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 case 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 April 2, 2009 relating to the Series 2009-A Bonds, the 2009-B Taxable Bonds and the Series 2009-C Bonds, 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 Foster Pepper PLLC, Bond Counsel, with respect to the validity of the Series 2009-A Bonds, the Series 2009-B Taxable Bonds and the Series 2009-C Bonds and with respect to the due authorization and issuance of the Series 2009-A Bonds, Series 2009-B Taxable Bonds and Series 2009-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 2009-A Bonds and the Series 2009-C 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"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"), 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 2009-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 2009-A Bonds and the Series 2009-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. We express no opinion as to whether some or all interest on the Series 2009-A Bonds and the Series 2009-C Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

Except as expressly stated herein, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2009-A Bonds, the Series 2009-B Taxable Bonds and the Series 2009-C Bonds.

Series 2009-B Taxable Bonds Circular 230 Disclaimer:

Investors are urged to obtain independent tax advice regarding the Series 2009-B Taxable Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2009-B Taxable Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2009-B Taxable Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2009 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			
	Flathead Electric Cooperative, Inc., Montana	0.123	0.370	0.257

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	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
	Salem Electric, Oregon	0.662	0.453	1.385

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	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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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 the Hanford Generating Project ("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.

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 2009 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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SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE 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.

"*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. The Supplemental Electric Revenue Bond Resolutions authorizing the 2009 Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the 2009 Bonds, any "Government Obligations" as that term is defined in Chap. 39.53 RCW and as it may be hereafter amended.

"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.

"Government Obligations" means (a) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (b) bonds, debentures, notes, participation certificates, or other obligations issued by the banks 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; (c) public housing bonds and project notes fully secured by contracts with the United States; and (d) obligations of financial institutions insured by the federal deposit insurance corporation or the federal savings and loan insurance corporation, to the extent insured or to the extent guaranteed as permitted under any provision of state law, as such definition may be amended.

"*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 on June 26, 1973, as amended and supplemented, and Resolution No. 775, adopted on 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, a division of The McGraw-Hill Companies, Inc. ("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.

"*Treasury Rate*" means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

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.

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 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, (ii) the amount required for the payment of interest due on each Payment Date, (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, (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 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. Money 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 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. In connection with each annual audit the independent auditor will prepare a report that states nothing came to their attention that caused them to believe that Energy Northwest failed to comply with the terms, covenants, provisions, or conditions of the Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution insofar as they relate to accounting matters or, if not in compliance therewith, the details of such failure to comply.

Consulting Engineer. So long as Energy Northwest owns and operates the Columbia Generating Station, Energy Northwest will retain on its staff one or more qualified engineers and hire an independent engineering firm when and as deemed necessary or advisable to provide immediate and continuous engineering counsel with respect to the Columbia Generating Station.

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 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 money, 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 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 2009-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 IRS 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.

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.

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.

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:

(xii) the amount included in the annual budget for fuel adopted pursuant to the Project 1 Project Agreement,

(xiii) all amounts received by Energy Northwest as fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(xiv) 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.

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:

(1) the amount included in the annual budget for fuel adopted pursuant to the Columbia Net Billing 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.

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.

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.

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.

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 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, 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 Prior Lien Bonds bears to the total amount of interest due on such next succeeding interest payment date on all such series of bonds.

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 4to 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.

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.

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.

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.

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.

Supplemental resolutions may be adopted 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.

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.

BOOK-ENTRY SYSTEM

The following information (except for the final paragraph) 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 DTC Participants (as hereinafter defined).

DTC will act as securities depository for the 2009 Bonds. The 2009 Bonds will be issued as fully-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 2009 Bond certificate will be issued for each maturity of the 2009 Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, and trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its DTC Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the 2009 Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the 2009 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2009 Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2009 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 the 2009 Bonds, except in the event that use of the book entry-entry system for the 2009 Bonds is discontinued.

To facilitate subsequent transfers, all 2009 Bonds deposited by DTC 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 2009 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 2009 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2009 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

When notices are given, they shall be sent by the Bond Registrar to DTC only. Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the 2009 Bonds 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 2009 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Energy Northwest 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 2009 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the 2009 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 Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by DTC 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 DTC Participant and not of DTC, the Bond Registrar, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2009 Bonds at any time by giving reasonable notice to Energy Northwest and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, 2009 Bond certificates are required to be printed and delivered.

Energy Northwest may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, 2009 Bond certificates will be printed and delivered to DTC.

With respect to 2009 Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Bond Registrar shall have no responsibility or obligation to any DTC Participant or to any person on behalf of whom a DTC Participant holds an interest in the 2009 Bonds with respect to, (i) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2009 Bonds; (ii) the delivery to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any notice with respect to the 2009 Bonds, including any notice of redemption; (iii) the payment to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the 2009 Bonds; (iv) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2009 Bonds; (v) any consent given action taken by DTC as registered owner; or (vi) any other matter. Energy Northwest and the Bond Registrar may treat and consider Cede & Co., in whose name each 2009 Bond is registered on the Bond Register, as the holder and absolute owner of such 2009 Bond for the purpose of payment of principal and interest with respect to such 2009 Bond, for the purpose of giving notices of redemption and other matters with respect to such 2009 Bond, for the purpose of registering transfers with respect to such 2009 Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the DTC Participant acquires an interest in the 2009 Bonds.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville will enter into written agreements (the "Disclosure Agreements") for the benefit of the holders and beneficial owners of the 2009 Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreements, which apply to any capitalized term used in the Disclosure Agreements, 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 2009 Bonds in the following tables in Appendix A under the heading "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS": "Federal System Statement of Revenues and Expenses" and "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments."

"Energy Northwest Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2009 Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of March 1, 2009" under the heading "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" and in the table labeled "Statement of Operations" under the heading "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION —Annual Costs."

"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 provide written notice of such change to each NRMSIR and the SID, if any.

"FCRPS" shall mean the Federal Columbia River Power System.

"FCRPS Fiscal Year" shall mean 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 end is changed, Bonneville shall provide written notice of such change to each NRMSIR and the SID, if any.

"MSRB" means the Municipal Securities Rulemaking Board or any successors 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 Disclosure Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Disclosure Agreement.

"SID" means a state information depository for the State of Washington, if any.

Financial Information.

Bonneville. Bonneville agrees to provide to each NRMSIR (or provide to a transmitting entity approved by the SEC) and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than March 31 of each year, commencing with the FCRPS Fiscal Year ending September 30, 2009:

(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 (or provide to a transmitting entity approved by the SEC), in each case as designated by the SEC in accordance with the Rule, no later than December 31 of each year, commencing with Energy Northwest Fiscal Year ending June 30, 2009:

(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 (or transmitting entity approved by 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 (or provide to a transmitting entity approved by the SEC), (i) notice of Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above and (ii) notice of Energy Northwest'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 (or provide to a transmitting entity approved by the SEC), notice of the occurrence of any of the following events with respect to the 2009 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 2009-A and the 2009-C Bonds;

(vii) Modifications to rights of 2009 Bondholders;

(viii) Optional, contingent or unscheduled calls of any 2009 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 2009 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 2009 Bonds.

Availability of Information from NRMSIRs and SID.

Bonneville and Energy Northwest have agreed to provide the foregoing information only to NRMSIRs and any SID. Prior to July 1, 2009, the information will be available to holders of 2009 Bonds only if the holders comply with the procedures and pay the charges established by such information vendors or obtain the information through securities brokers who do so.

Effective July 1, 2009, all such information must be filed with the MSRB, rather than the current NRMSIRs. The MSRB has indicated that it intends to make the information available to the public without charge through an internet portal.

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 2009 Bonds. This section, or any provision hereof, shall be null and void if Bonneville and Energy Northwest (i) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule that require this Disclosure Agreement, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the 2009 Bonds; and (ii) notifies each then existing NRMSIR (or transmitting entity approved by the SEC) and the SID, if any, of such opinion and the cancellation of this Disclosure Agreement.

In the event of any amendment or waiver of a provision of this Disclosure 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 under Section 3, 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 2009 Bonds to enforce the provisions of this Disclosure Agreement against Energy Northwest shall be limited to a right to obtain specific enforcement of Energy Northwest's obligations hereunder, and any failure by Energy Northwest to comply with the provisions of this Disclosure Agreement shall not be an event of default under the Resolution or the Supplemental Resolution or with respect to the 2009 Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Disclosure Agreement. Owners and Beneficial Owners of 2009 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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ENERGY NORTHWEST • PROJECT 1, COLUMBIA & PROJECT 3 ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2009 - APRIL 2, 2009

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