NEW ISSUE — BOOK-ENTRY ONLY

Series 2012-D Bonds: *In the opinion of Orrick, Herrington & Sutcliffe LLP, 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 2012-D Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act") and Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). In the further opinion of Special Tax Counsel, interest on the Series 2012-D Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings when calculating federal corporate alternative minimum taxable income. See "TAX MATTERS—SERIES 2012-D BONDS" herein.*

Series 2012-E (Taxable) Bonds: *In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2012-E (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, or Section 103 of the Code. See "TAX MATTERS—SERIES 2012-E (TAXABLE) BONDS" herein.*

$782,655,000
ENERGY NORTHWEST
$34,140,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-D
$748,515,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable)

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

The Series 2012-D Bonds are being issued for the purpose of paying costs of replacing the main condenser and various other capital improvements to the Columbia Generating Station and paying costs of issuing the Series 2012-D Bonds. The Series 2012-E (Taxable) Bonds (together with the Series 2012-D Bonds, the "Series 2012-D/E Bonds") are being issued for the purpose (directly or indirectly through repayment of the Columbia Note (as described herein)) of paying fuel related costs and various other expenses for the Columbia Generating Station, including paying a portion of the costs of replacing the main condenser, capitalizing interest and paying costs of issuing the Series 2012-E (Taxable) Bonds. See "PURPOSE OF ISSUANCE" herein.

The Series 2012-D/E Bonds will be issued in fully registered form, registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Series 2012-D/E Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the registered owner of the Series 2012-D/E Bonds and nominee of DTC, references herein to holders or registered owners shall mean Cede & Co. and shall not mean the beneficial owners of the Series 2012-D/E Bonds. Principal of the Series 2012-D/E Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., Seattle, Washington, as Trustee for the Series 2012-D/E Bonds. Interest on the Series 2012-D/E Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2013. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2012-D/E 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 SERIES 2012-D/E BONDS—GENERAL—Book-Entry System; Transferability and Registration" and Appendix I—"BOOK-ENTRY SYSTEM" herein.

The Series 2012-D/E Bonds are subject to optional redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE SERIES 2012-D/E BONDS—REDEMPTION" *herein.*

The Series 2012-D/E 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 Series 2012-D/E 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. The Columbia Generation Station is a separate project of Energy Northwest, and the Series 2012-D/E Bonds are payable solely from the revenues of the Columbia Generating Station. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover Page

The Series 2012-D/E 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 Series 2012-D/E Bonds will be available for delivery through the facilities of DTC on or about August 23, 2012.

BofA Merrill Lynch **Citigroup** **Goldman, Sachs & Co.**

August 15, 2012

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS, PRICES AND CUSIP NUMBERS

$34,140,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE BONDS, SERIES 2012-D

Year (July 1)	Amount	Interest Rate	Yield	CUSIP No.*
2025	$ 1,180,000	5.00%	2.50%**	29270CXZ3
2026	1,225,000	5.00	2.57**	29270CYA7
2027	1,290,000	5.00	2.64**	29270CYB5
2028	1,350,000	5.00	2.71**	29270CYC3
2029	1,420,000	5.00	2.78**	29270CYD1
2030	1,490,000	5.00	2.85**	29270CYE9
2031	1,565,000	5.00	2.91**	29270CYF6
2032	1,645,000	5.00	2.97**	29270CYG4

$5,370,000 5.00% Term Bonds due July 1, 2035 at a yield of 3.24%**; CUSIP No.: 29270CYJ8

$17,605,000 4.00% Term Bonds due July 1, 2044 at a yield of 4.10%; CUSIP No.: 29270CYH2

$748,515,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE BONDS, SERIES 2012-E (TAXABLE)

Year (July 1)	Amount	Interest Rate	Price	CUSIP No.*
2015	$ 25,485,000	1.063%	100%	29270CYK5
2018	116,930,000	2.147	100	29270CYL3
2020	103,235,000	2.653	100	29270CYN9
2021	94,720,000	2.803	100	29270CYP4
2022	77,840,000	2.953	100	29270CYQ2
2023	12,970,000	3.103	100	29270CYR0
2024	14,580,000	3.253	100	29270CYS8
2025	15,620,000	3.403	100	29270CYT6
2026	18,650,000	3.503	100	29270CYU3
2027	14,960,000	3.603	100	29270CYV1

$250,000,000 2.197% Term Bonds due July 1, 2019*** at a price of 100%; CUSIP No.: 29270CYM1

$3,525,000 4.144% Term Bonds due July 1, 2037 at a price of 100%; CUSIP No.: 29270CYW9

* The CUSIP numbers are provided by CUSIP Global Services, managed on behalf of the American Bankers Association by Standard & Poor's. The CUSIP numbers are not intended to create a database and do not serve in any way as a substitute for CUSIP service. CUSIP numbers are provided for convenience and reference only, and are subject to change. Neither Energy Northwest nor the Underwriters take responsibility for the accuracy of the CUSIP numbers.

** Priced to the July 1, 2022, par call date.

*** A portion of the Series 2012-E (Taxable) Bonds July 1, 2019 Term Bonds has a sinking fund installment due on July 1, 2018, which is also a serial bond maturity date for the Series 2012-E (Taxable) Bonds. See "DESCRIPTION OF THE SERIES 2012-D/E BONDS—Redemption."

ENERGY NORTHWEST
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Sid W. Morrison, Chairman
Jack Janda, Vice Chairman
Kathleen Vaughn, Secretary
David Remington, Assistant Secretary
Marc Daudon
Dan G. Gunkel
Lawrence Kenney
Skip Orser
Will Purser
Lori Sanders
Tim Sheldon

Administrative Staff

Chief Executive Officer	Mark E. Reddemann
Vice President, Nuclear Generation/Chief Nuclear Officer	Brad J. Sawatzke
Vice President, Employee Development/Corporate Services	Dale K. Atkinson
Acting Vice President, Energy/Business Services	Theodore J. Beatty
Vice President, Engineering	Alex Javorik
Vice President, Operations	William G. Hettel
Vice President, Chief Financial Officer/Chief Risk Officer	Brent J. Ridge
General Counsel	Robert Dutton

Financial Advisor
Public Financial Management, Inc.

Bond and Disclosure Counsel
Foster Pepper PLLC

Trustee for the Series 2012-D/E Bonds
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	William K. Drummond
Chief Operating Officer	Anita J. Decker
Executive Vice President and General Counsel	Randy A. Roach
Executive Vice President and Chief Financial Officer	Claudia R. Andrews

Special Counsel and Special Tax Counsel
Orrick, Herrington & Sutcliffe LLP

No dealer, broker, salesperson or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations in connection with the issuance and sale of the Series 2012-D/E Bonds, 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 Series 2012-D/E 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, may 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 SERIES 2012-D/E BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF THE SERIES 2012-D/E 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

$782,655,000

ENERGY NORTHWEST

$34,140,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-D

$748,515,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable)

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of the Series 2012-D/E Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the Series 2012-D/E 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 $34,140,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2012-D (the "Series 2012-D Bonds") and $748,515,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable) (the "Series 2012-E (Taxable) Bonds"). The Series 2012-D Bonds and the Series 2012-E (Taxable) Bonds are collectively referred to herein as the "Series 2012-D/E Bonds."

The Series 2012-D Bonds are being issued pursuant to Chapters 39.46 and 43.52 of the Revised Code of Washington, as amended (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 paying costs of replacing the main condenser and various other capital improvements to the Columbia Generating Station, and paying costs of issuing the Series 2012-D Bonds. The Series 2012-E (Taxable) Bonds are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution for the purpose (directly or indirectly through repayment of the Columbia Note (as described herein)) of paying fuel related costs and various other expenses for the Columbia Generating Station, including paying a portion of the costs of replacing the main condenser, capitalizing interest and paying costs of issuing the Series 2012-E (Taxable) Bonds. See "PURPOSE OF ISSUANCE." Bonds issued pursuant to the Columbia Electric Revenue Bond Resolution are referred to herein as the "Columbia Electric Revenue Bonds." Energy Northwest has other indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution.

Energy Northwest may issue bonds pursuant to the Act and Resolution No. 835, adopted on November 23, 1993 (as amended and supplemented, the "Project 1 Electric Revenue Bond Resolution"). Energy Northwest has indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution. In addition, Energy Northwest has indebtedness currently outstanding under Resolution No. 769, adopted on September 18, 1975 (as amended and supplemented, the "Project 1 Prior Lien Resolution"). 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." Energy Northwest is not issuing any Project 1 bonds at this time.

Energy Northwest may issue bonds 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 Columbia Electric Revenue Bond Resolution and the Project 1 Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions"). Energy Northwest has indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution. In addition, Energy Northwest has 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, the "Prior Lien Resolutions"). Bonds issued pursuant to the Project 3 Prior Lien Resolution are referred to herein as the "Project 3 Prior Lien Bonds," and the Project 3 Prior Lien Bonds together with the Project 1 Prior Lien Bonds, are collectively referred to herein as the "Prior Lien Bonds." As of July 1, 2012, Columbia does not have any prior lien bonds outstanding. 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 Columbia Electric Revenue Bonds and the Project 1 Electric Revenue Bonds, are collectively referred to herein as the "Electric Revenue Bonds." Energy Northwest is not issuing any Project 3 bonds at this time.

The Prior Lien Bonds, the Electric Revenue Bonds, including the Series 2012-D/E 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."

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 2009, Energy Northwest added three new members: Jefferson County and Lewis County Public Utility Districts and the City of Centralia. In 2010, Energy Northwest added Public Utility District No. 1 of Pend Oreille County as another member. As of August 1, 2012, Public Utility District No. 1 of Whatcom County is no longer a member of Energy Northwest. Energy Northwest now has 27 members, consisting of 22 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Energy Northwest has the authority, among other things, to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power and energy and to issue bonds and other evidences of indebtedness to finance the same.

Energy Northwest owns and operates the Columbia Generating Station, a nuclear electric generating station with a net design electric rating of 1,157 megawatts. Energy Northwest also owns and operates a 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. In addition, Energy Northwest owned 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 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 the Net Billed Projects. As more fully discussed under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS," Bonneville is obligated to pay Energy Northwest for such capability pursuant to Net Billing Agreements (hereinafter defined) for the Net Billed Projects, 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 the Net Billed Projects.

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 125 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, parts of western Montana and small portions of northern California, northern Nevada, northern Utah and western Wyoming (sometimes referred to herein as the "Pacific Northwest," the "Northwest," the "Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately 12 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 SERIES 2012-D/E BONDS

The Series 2012-D/E Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Series 2012-D/E 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."

There are no restrictions on the issuance of debt under the Electric Revenue Bond Resolutions or 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 Project 1 Prior Lien Bonds and Project 3 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. Energy Northwest has covenanted that it will not issue any bonds of the Columbia Generating Station with a lien superior to the Columbia Electric System Bonds.

The Series 2012-D/E Bonds are secured 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 Columbia secure only the Series 2012-D/E Bonds and other Columbia Electric Revenue Bonds. Accordingly, the owners of the Series 2012-D/E Bonds 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 July 2, 2012, 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 Electric Revenue Bond Resolution related to Columbia for debt service and for all other purposes of Columbia. 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 Projects 1 and 3 for debt service and for all other purposes of Project 1 and Project 3. 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 generally are required to be made directly by the Participants, not directly by Bonneville. 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 is required to pay 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 make payments to the United States Treasury only 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 each Net Billing Agreement 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 SERIES 2012-D/E BONDS

GENERAL

The Series 2012-D/E Bonds are dated the date of their delivery, and mature on July 1 in the years and in the principal amounts shown on the inside cover page of this Official Statement. The Series 2012-D/E Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2013, at the rates shown on the inside cover page of this Official Statement. Interest on the Series 2012-D/E 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 Series 2012-D/E Bonds (collectively, the "Trustee"). For so long as the Series 2012-D/E 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 Series 2012-D/E Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the Series 2012-D/E Bonds will not receive certificates representing their interests in such Series 2012-D/E Bonds purchased, except as described in Appendix I—"BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as initial securities depository for the Series 2012-D/E Bonds. As discussed in Appendix I—"BOOK-ENTRY SYSTEM," transfers of ownership interests in the Series 2012-D/E Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the Series 2012-D/E Bonds. Energy Northwest, the Trustee and any other person may treat the registered owner of any Series 2012-D/E Bonds as the absolute owner of such Series 2012-D/E Bonds 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 Series 2012-D/E Bonds shall be overdue or not. All payments of or on account of interest or principal to any registered owner of any such Series 2012-D/E Bonds shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such Series 2012-D/E Bonds, to the extent of the sum or sums paid.

When Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bond is registered, as the holder and absolute owner of such Series 2012-D/E 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 Series 2012-D/E Bonds, Series 2012-D/E Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the Series 2012-D/E Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the Series 2012-D/E Bonds will be payable by check or draft mailed to the persons in whose names such Series 2012-D/E 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 the Series 2012-D/E Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. If the book-entry transfer system for the Series 2012-D/E Bonds is discontinued, registered ownership of any Series 2012-D/E Bond may be transferred or exchanged by surrendering such Series 2012-D/E Bond to the Trustee, with the assignment form appearing on the Series 2012-D/E Bond duly executed. The Trustee shall not be required to transfer any Series 2012-D/E Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

Series 2012-D Bonds. The Series 2012-D Bonds are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2022, in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at a Redemption Price equal to 100% of the principal amount of the Series 2012-D Bonds to be redeemed, plus interest accrued to the date of redemption.

Series 2012-E (Taxable) Bonds. The Series 2012-E (Taxable) Bonds are subject to redemption prior to their respective maturities at the option of Energy Northwest (with the approval of Bonneville), in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The "Make-Whole Redemption Price" is the greater of (i) the issue price as shown on the inside cover page of this Official Statement (but not less than 100% of the principal amount of the Series 2012-E (Taxable) Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2012-E (Taxable) Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2012-E (Taxable) Bonds are to be redeemed, discounted to the date on which such Series 2012-E (Taxable) Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below) plus 20 basis points, plus accrued and unpaid interest on the Series 2012-E (Taxable) Bonds to be redeemed on the redemption date.

"Business Day" means a day other than a day on which commercial banks located in Seattle, Washington or New York, New York are required or authorized by law to close.

"Comparable Treasury Issue" means, with respect to any redemption date for a particular Series 2012-E (Taxable) Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2012-E (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 average life of such Series 2012-E (Taxable) Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date for a particular Series 2012-E (Taxable) Bond, (i) the most recent yield data for the applicable U.S. Treasury maturity index from the Federal Reserve Statistical Release H.15 Daily Update (or any comparable or successor publication) reported, as of 11:00 a.m. New York City time, on the Valuation Date; or (ii) if the yield described in (i) above is not reported as of such time or the yield reported as of such time is not ascertainable, the average of five Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or if the Designated Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all such quotations.

"Designated Investment Banker" means one of the Reference Treasury Dealers appointed by Energy Northwest (with the approval of Bonneville).

"Reference Treasury Dealer" means each of five firms, specified by Energy Northwest (with the approval of Bonneville) from time to time, that are primary U.S. Government securities dealers in the City of New York (each, a "Primary Treasury Dealer"); provided, however, that if any of them ceases to be a Primary Treasury Dealer, Energy Northwest will substitute another Primary Treasury Dealer (with the approval of Bonneville).

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2012-E (Taxable) Bond, the average, as determined by the Designated Investment Banker, 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 Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2012-E (Taxable) Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price (defined below), as calculated by the Designated Investment Banker (defined below).

"Valuation Date" means a date that is no earlier than four days prior to the date the redemption notice is to be mailed.

Mandatory Redemption

The Series 2012-D Bonds maturing on July 1, 2035 and July 1, 2044, and the Series 2012-E (Taxable) Bonds maturing on July 1, 2019 and July 1, 2037 (all 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 as shown in the tables below (to the extent such Series 2012-D/E Bonds have not been previously redeemed or purchased) and in the sinking fund installments set forth below, without premium, together with the interest accrued to the date fixed for redemption.

Series 2012-D Bonds – 2035 Term Bonds

Year (July 1)	Sinking Fund Installment
2033	$ 1,715,000
2034	1,845,000
2035*	1,810,000

* Maturity.

Series 2012-D Bonds – 2044 Term Bonds

Year (July 1)	Sinking Fund Installment
2038	$ 2,140,000
2039	2,220,000
2040	2,325,000
2041	2,375,000
2042	2,610,000
2043	2,290,000
2044*	3,645,000

* Final maturity.

Series 2012-E (Taxable) Bonds – 2019 Term Bonds

Year (July 1)	Sinking Fund Installment
2018	62,550,000
2019*	187,450,000

* Maturity.

Series 2012-E (Taxable) Bonds – 2037 Term Bonds

Year (July 1)	Sinking Fund Installment
2036	$ 2,275,000
2037*	1,250,000

* Final maturity.

Upon the purchase or redemption of Series 2012-D/E Bonds for which mandatory sinking fund installments have been established, other than by reason of the mandatory sinking fund installment redemption described above, an amount equal to the principal amount of the Series 2012-D/E Bonds so purchased or redeemed shall be credited toward each of the mandatory sinking fund installments with respect to such Series 2012-D/E Bonds of such maturity on a pro rata basis.

Partial Redemption

If less than all of the Series 2012-D/E Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities to be redeemed. If less than all of the Series 2012-D/E Bonds of a Series of any maturity are to be redeemed, the Series 2012-D/E Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot for the Series 2012-D Bonds or in accordance with their respective standard procedures. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any Series 2012-D/E 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 Series 2012-D/E Bonds for redemption, the Trustee will treat each such Series 2012-D/E Bonds as representing that number of such Series 2012-D/E Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2012-D/E Bonds to be redeemed in part by $5,000.

The particular Series 2012-E (Taxable) Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2012-E (Taxable) Bonds are registered in book-entry only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2012-E (Taxable) Bonds, if less than all of a maturity of the Series 2012-E (Taxable) Bonds of a maturity are called for redemption, the particular Series 2012-E (Taxable) Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2012-E (Taxable) Bonds are held in book-entry form, the selection for redemption of such Series 2012-E (Taxable) Bonds shall be made in accordance with the operational arrangements of DTC then in effect. It is Energy Northwest's intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between Energy Northwest and the Beneficial Owners be made in accordance with the pro rata pass-through distribution of principal basis described below. However, Energy Northwest can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among registered owners on such basis. If the DTC operational arrangements do not allow for the redemption of the Series 2012-E (Taxable) Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2012-E (Taxable) Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

If the Series 2012-E (Taxable) Bonds are not registered in book-entry only form, any redemption of less than all of a maturity of the Series 2012-E (Taxable) Bonds shall be allocated among the registered owners of such Series 2012-E (Taxable) Bonds as nearly as practicable in proportion to the principal amounts of the Series 2012-E (Taxable) Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2012-E (Taxable) Bonds. This will be calculated based on the following formula:

$$\frac{\text{(principal amount to be redeemed) x (principal amount owned by registered owner)}}{\text{(principal amount outstanding)}}$$

Notice of Redemption

Notice of redemption of any Series 2012-D/E Bonds is to be given by the Trustee by first-class mail not less than 20 days nor more than 60 days before the redemption date to the registered owners of the Series 2012-D/E Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2012-D/E Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2012-D/E 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 Series 2012-D/E Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2012-D/E 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 Series 2012-D/E Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2012-D/E Bonds on the redemption date and the Series 2012-D/E 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 Series 2012-D/E Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2012-D/E Bonds.

Neither Energy Northwest, the Trustee, nor the Underwriters can give any assurance that DTC, the Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2012-D/E Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any Series 2012-D/E 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 Series 2012-D/E Bond, and such Series 2012-D/E 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 Series 2012-D/E 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 separate paying agent for such Series 2012-D/E Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) money 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 agent pertaining to such Series 2012-D/E Bond. 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 Series 2012-D/E Bonds.

If Energy Northwest defeases any Series 2012-E (Taxable) Bond, such Series 2012-E (Taxable) Bond may be deemed to be retired and "reissued" for federal income tax purposes as a result of the defeasance. In that event, the Beneficial Owner of the Series 2012-E (Taxable) Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the Beneficial Owner's adjusted tax basis in the Series 2012-E (Taxable) Bond. See "TAX MATTERS."

PURPOSE OF ISSUANCE

The Series 2012-D Bonds are being issued for the purpose of replacing the main condenser and various other capital improvements to the Columbia Generating Station and paying costs of issuing the Series 2012-D Bonds.

The Series 2012-E (Taxable) Bonds are being issued for the purpose (directly or indirectly through repayment of the Columbia Note (as described below)) of paying the costs of acquiring fuel for the Columbia Generating Station; financing repairs, renewals and improvements or betterments to and operating expenses of the Columbia Generating Station (if proceeds are not needed for the prior purposes), including paying a portion of the costs of replacing the main condenser; capitalizing interest; and paying costs of issuing the Series 2012-E (Taxable) Bonds. For additional information regarding Energy Northwest's fuel purchase, see "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION—Depleted Uranium Enrichment Program."

Bank of America, N.A. extended a line of credit to Energy Northwest for Columbia pursuant to a Loan Agreement (the "Columbia Loan Agreement"). Under the Columbia Loan Agreement, Energy Northwest is expected to have borrowed $143,006,529 from time to time during the period from May 15, 2012 through August 23, 2012. Proceeds of advances made under the Columbia Loan Agreement were applied to acquire fuel for the Columbia Generating Station. Energy Northwest's obligation to repay advances under the Columbia Loan Agreement is evidenced by a bond anticipation note (the "Columbia Note") executed and delivered by Energy Northwest pursuant to a Separate Subordinated Resolution adopted on May 10, 2012. The Columbia Note is secured on a parity with the Columbia Electric Revenue Bonds issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Columbia Separate Subordinated Resolutions. A portion of the proceeds of the Series 2012-E (Taxable) (Taxable) will be applied to repay the Columbia Note.

SOURCES AND USES OF FUNDS

SOURCES OF FUNDS

Principal of Series 2012-D Bonds	$ 34,140,000
Principal of Series 2012-E (Taxable) Bonds	748,515,000
Net Original Issue Premium	2,627,135
Total	$ 785,282,135

USES OF FUNDS

Main Condenser Replacement Project	$ 40,000,000
Fuel Acquisition and Other Expenses	567,743,471
Columbia Note Repayment	143,006,529
Capitalized Interest	30,810,917
Costs of Issuing Series 2012-D/E Bonds (including Underwriters' compensation)	3,721,218
Total	$ 785,282,135

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Series 2012-D/E 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. The Series 2012-D/E Bonds are a charge on the receipts, income and revenues of Columbia subordinate to the payments required to be made 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 Electric Revenue Bonds, including the Series 2012-D/E Bonds, also are 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 Series 2012-D/E 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 and other obligations of Energy Northwest issued pursuant to any Columbia Separate Subordinated Resolution. There were outstanding as of July 2, 2012, $2,441,385,000 principal amount of Columbia Electric Revenue Bonds. There are no Columbia prior lien bonds outstanding.

As of July 2, 2012, there were $41,070,000 Project 1 Prior Lien Bonds outstanding. There were outstanding as of July 2, 2012, $1,279,990,000 principal amount of Project 1 Electric Revenue Bonds.

As of July 2, 2012, there were $222,555,000 Project 3 Prior Lien Bonds outstanding. There were outstanding as of July 2, 2012, $1,172,850,000 principal amount of Project 3 Electric Revenue Bonds.

Energy Northwest has covenanted with the owners of the Project 1 Electric Revenue Bonds and Project 3 Electric Revenue Bonds that it will not issue any more Project 1 Prior Lien Bonds, Project 3 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 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 Series 2012-D/E Bonds. 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 when due the principal of and premium, if any, and interest on the Columbia Electric Revenue Bonds, including the Series 2012-D/E Bonds. See "NET BILLING AND RELATED AGREEMENTS" below.

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 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 when due the principal of and premium, if any, and interest on the Project 1 Electric Revenue 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 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 when due the principal of and premium, if any, and interest on the Project 3 Electric Revenue 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 Series 2012-D/E Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Series 2012-D/E Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest. No Bondholder has a claim on the assets of any Project.

The Series 2012-D/E 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 Series 2012-D/E 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 both Prior Lien Resolutions, 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 for 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 PROJECT 1 AND PROJECT 3 PRIOR LIEN RESOLUTIONS—Events of Default; Remedies."

Under both 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 PROJECT 1 AND PROJECT 3 PRIOR LIEN RESOLUTIONS—Certain Covenants."

If the maturity of Prior Lien Bonds or Electric Revenue Bonds, including the Series 2012-D/E Bonds, were accelerated by the applicable Bond Fund Trustee or Trustee or the holders of the requisite principal amount of such bonds after an Event of Default under the respective Prior Lien Resolution or Electric Revenue Bond Resolution, no assurance can be given that the principal amount of the accelerated Prior Lien Bonds or Electric Revenue Bonds would be payable currently as a cost under the terms of the Net Billing Agreements related to such Net Billed Project. See "NET BILLING AND RELATED

AGREEMENTS—Payment Procedures" and "SECURITY FOR THE NET BILLED BONDS—LIMITATIONS ON REMEDIES" for a discussion of the limitations of certain remedies. The Columbia Note described under "PURPOSE OF ISSUANCE" is also subject to acceleration under the Columbia Loan Agreement.

If Bonneville and the Participants were obligated only to provide funds to meet the scheduled amounts due on the Project 1 Prior Lien Bonds or the Project 3 Prior Lien Bonds and not the amounts due upon acceleration, money intended to be applied to the payment of the respective Project 1 Electric Revenue Bonds and Project 3 Electric Revenue Bonds would be applied by the applicable Prior Lien Bond Fund Trustee to payment of such Project 1 Prior Lien Bonds or Project 3 Prior Lien Bonds, and the Project 1 Electric Revenue Bonds and Project 3 Electric Revenue Bonds would not be paid until such Project 1 Prior Lien Bonds or Project 3 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 PROJECT 1 AND PROJECT 3 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 the Net Billed Projects 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 Project 1 Prior Lien Bonds or Project 3 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 Bond Fund Trustee until all such Project 1 Prior Lien Bonds or Project 3 Prior Lien Bonds have been paid in full or such Event of Default has been cured, whichever occurs first. In such event, money intended to be applied to the payment of related Electric Revenue Bonds would be paid instead to the applicable Bond Fund Trustee and such Electric Revenue Bonds would not be paid until such Project 1 Prior Lien Bonds or Project 3 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 Series 2012-D/E 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 Series 2012-D/E Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the Series 2012-D/E 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 Series 2012-D/E 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 opinion to be delivered by Foster Pepper PLLC, as Bond Counsel, concurrently with the issuance of the Series 2012-D/E Bonds will be subject to such limitations. See Appendix D-1—"PROPOSED FORM OF OPINION OF BOND COUNSEL FOR THE SERIES 2012-D/E BONDS," and Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINION OF BOND COUNSEL FOR THE SERIES 2012-D/E BONDS."

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the Series 2012-D/E 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

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 or 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. The Columbia Note that is to be paid from a portion of the proceeds of the Series 2012-E (Taxable) Bonds was issued pursuant to a Separate Subordinated Resolution. See "PURPOSE OF ISSUANCE." 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 Series 2012-D/E 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. The Project 1 Electric Revenue Bonds and the Project 3 Electric Revenue Bonds are subordinate to the Project 1 Prior Lien Bonds and the Project 3 Prior Lien Bonds, respectively.

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 (as amended, 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 (as amended, 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 2013 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2013 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 "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 "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 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 Project 1 and Project 3 have been terminated, Energy Northwest is required under each of the Project 1 Net Billing Agreements and Project 3 Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Project 1 Participant and 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 and 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 Project 1 and Project 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 "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 Voluntary Payment 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 "—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% share of the terminated Trojan Nuclear Project owned by the City of Eugene, Oregon, acting by and through the Eugene Water and Electric Board. 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 with Participants requiring net billing to fund resource acquisitions or other capital program investments, although Bonneville is exploring the use of billing credits relating to prepayments by Participants of future power bills.

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 are required to 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 2011 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 make payments to the United States Treasury only 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 Net Billing Agreements for each Net Billed Project is to pay an amount equal to the costs of such Net Billed Project less any other funds which are required to be specified in the Annual Budget as payable from sources other than the payments to be made under such Net Billing Agreements. 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 had 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, 2011" 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, 2011. PricewaterhouseCoopers LLP has not participated in the preparation of or performed any procedures related to this Official Statement.

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 July 2, 2012. For information with respect to the Columbia Note issued on May 15, 2012, see "PURPOSE OF ISSUANCE."

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF JULY 2, 2012

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 41,070,000
Electric Revenue Refunding Bonds	1,279,990,000
TOTAL PROJECT 1	$ 1,321,060,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 0
Electric Revenue and Refunding Bonds	2,441,385,000
TOTAL COLUMBIA	$ 2,441,385,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 222,555,000 (1)
Electric Revenue Refunding Bonds	1,172,850,000
TOTAL PROJECT 3	$ 1,395,405,000
TOTAL NET BILLED REVENUE BONDS	$ 5,157,850,000
Nine Canyon Wind Project Revenue Bonds (2)	$ 130,955,000

(1) Includes $111,334,400 accreted value of Compound Interest Bonds for Project 3, as of July 1, 2012.
(2) Bonneville is not a party to any agreements that secure payment of the Nine Canyon Wind Project Revenue Bonds.

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, allowing Bonneville to advance the amortization of Bonneville's United States Treasury debt. 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 Management 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 Projects 1 and 3 Net Billed Bonds for any future refinancing of such bonds. An additional objective of the Refunding Plan is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville. A number of the Electric Revenue and Refunding Bonds reflected in the previous table also were issued as part of the Debt Optimization Program or Refunding Plan.

Bonneville and Energy Northwest currently do not expect to undertake future Energy Northwest debt refundings for the purpose of implementing the Debt Optimization Program. However, Bonneville and Energy Northwest do expect to undertake future refundings which extend maturities of outstanding Energy Northwest debt. The purpose of these refundings would be to extend final Energy Northwest debt maturities in order to enable Bonneville to maintain financial flexibility to meet its financial requirements.

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 27, consisting of 22 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Any public utility district and any municipal entity within the State of Washington authorized to engage in the business of generating or distributing electricity may join Energy Northwest.

Energy Northwest has its principal office in Richland, Washington. The Board of Directors of Energy Northwest is comprised of 27 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 2013
Jack Janda, Vice Chairman	Public Utility District Commissioner	June 2014
Kathleen Vaughn, Secretary	Public Utility District Commissioner	June 2014
David Remington, Assistant Secretary	Financial Consultant	June 2012*
Marc Daudon	Management Consultant	June 2014
Dan G. Gunkel	Public Utility District Commissioner	June 2014
Lawrence Kenney	Retired Organized Labor Executive	June 2014
Skip Orser	Retired Nuclear Executive	June 2014
Will Purser	Public Utility District Commissioner	June 2014
Lori Sanders	Public Utility District Commissioner	June 2014
Tim Sheldon	Washington State Senator	June 2016

* David Remington is considered a member of the Executive Board until reappointed, or his appointment is rescinded or another member is appointed by the Governor of the State of Washington.

MANAGEMENT

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

Name	Position	Nuclear Industry Experience
Mark E. Reddemann	Chief Executive Officer	32 years
Brad J. Sawatzke	Vice President, Nuclear Generation/Chief Nuclear Officer	29 years
Dale K. Atkinson	Vice President, Employee Development/Corporate Services	33 years
Theodore J. Beatty	Acting Vice President, Energy/Business Services*	11 years
Alex Javorik	Vice President, Engineering	31 years
William G. Hettel	Vice President, Operations	29 years
		Experience
Brent J. Ridge	Vice President, Chief Financial Officer/Chief Risk Officer	21 years
Robert Dutton	General Counsel	24 years

* Energy Northwest is currently recruiting for the Vice President, Energy/Business Services position.

EMPLOYEES

Energy Northwest currently employs approximately 1,169 employees. Of these employees, 317 are members of the International Brotherhood of Electrical Workers ("IBEW"), 144 are members of the United Steel Workers ("USW") and eight 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. Negotiations with the Nuclear bargaining unit have been underway since April 2012, and the other bargaining groups are expected to begin negotiations in the summer and fall of 2012. A no-strike clause is included in each of the agreements. Energy Northwest considers labor relations to be satisfactory.

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 of 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 PROJECT 1 AND PROJECT 3 PRIOR LIEN RESOLUTIONS—Other Funds Established by the Prior Lien Resolutions; Flow of Revenues."

RETIREMENT PLANS AND OTHER POST-EMPLOYMENT BENEFITS

Energy Northwest participates in the retirement plans administered by the State of Washington. Energy Northwest also offers a 401(k) Deferred Compensation Plan, a 457 Deferred Compensation Plan and other post-employment benefits. For information on these plans, see Notes 7 through 9 in the Audited Financial Statements of Energy Northwest Projects for the Year Ended June 30, 2011, attached hereto as Appendix C.

THE COLUMBIA GENERATING STATION

Description

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 "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

In May 2012, the Nuclear Regulatory Commission ("NRC") approved Columbia's 40-year operating license for an additional 20-years, extending operation of Columbia to 2043.

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest originally had a maintenance, operating, fuel and capital budget for Columbia of $308 million for the 2012 fiscal year, which ended on June 30, 2012, however, such amount was amended to $335 million for the 2012 fiscal year due to the extended outage. It is expected that Columbia's actual maintenance, operating, fuel and capital expenditures will be $335 million for the 2012 fiscal year.

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 was originally budgeted at $32.90 per megawatt-hour for the 2012 fiscal year, however, this amount was amended to $47.98 per megawatt-hour for the 2012 fiscal year due to the extended outage. This cost is lower than the $55.18 per megawatt-hour for the 2011 fiscal year because the 2011 fiscal year included the refueling and maintenance outage. The actual cost of production for the 2012 fiscal year was $47.34 per megawatt-hour, and is projected to be $43.47 per megawatt-hour in fiscal year 2013 and $34.40 per megawatt-hour in fiscal year 2014. Energy Northwest continues to place a high priority on cost-containment.

Columbia Generating Station ended its longest continuous operation at 505 days on April 1, 2011 at the request of Bonneville because of the high water flow through the federal hydroelectric system. The 174-day outage began on April 6. It was expected that the outage would be completed in July, but due to contractor delays, ended on September 27, 2011. Energy Northwest times the biennial refueling outages to coincide with the springtime snow melt and runoff, a time when hydroelectric power is generally available in the market at the lowest cost. This minimizes the cost of replacement power for the region while Columbia is off-line. During the 2011 outage, approximately one-third of Columbia's 764 fuel assemblies were replaced with fresh fuel assemblies, and the plant's main condenser was replaced. This was the largest project undertaken at Columbia.

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.

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 71.7% and has generated 187,454,358 megawatt hours (net of station use) of electric power through December 2011. However, in the ten calendar years ending December 31, 2011, the cumulative capacity factor, without economic dispatch, was 83.8%.

Successful implementation of employee performance enhancement initiatives at Columbia has produced significant positive results in plant performance. The three best generating fiscal years at Columbia since commencing commercial operation have been in the last eight years. Columbia produced 7,247 million kilowatt hours of electric power in fiscal year 2011, as compared to 8,124 million kilowatt hours in fiscal year 2010. Generation decreased 10.8% from fiscal year 2010 due to the biennial refueling and maintenance outage cycle.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for fiscal years ended June 30, 2010 and 2011, and from the preliminary financial statements for the fiscal year ended June 30, 2012, 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 2010	FY 2011	FY 2012
Operations, Maintenance and Overhead	$204,973	$274,366	$204,250
Nuclear Fuel	35,433	30,772	35,393
Spent Fuel Disposal Fee	7,655	6,845	6,560
Generation Taxes	3,708	3,166	3,239
Decommissioning	6,766	7,090	7,433
Depreciation and Amortization	75,883	66,636	74,440
Investment Income	(475)	(721)	(467)
Interest Expense and Discount Amortization	115,430	119,792	123,937
Other Expense/(Revenue)	(1,298)	14,210	(55,387)[2]
Total Costs	$448,075	$522,156	$399,398
Net Generation (GWhs)	8,124	7,247[3]	6,984[4]

(1) Dollar amounts derived from audited Energy Northwest financial statements for fiscal years 2010 and 2011, and from the unaudited financial statements for the 2012 fiscal year.
(2) Due to litigation costs.
(3) The decrease in generation from fiscal year 2010 to fiscal year 2011 was due to the biennial refueling and maintenance outage cycle.
(4) The decrease in generation from fiscal year 2011 to fiscal year 2012 was due to the extended outage.

The preliminary financial data included in the body of this Official Statement has been prepared by, and is the responsibility of, Energy Northwest. PricewaterhouseCoopers LLP has not audited, reviewed, compiled or performed any procedures with respect to the accompanying preliminary financial data. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto.

Capital Improvements

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. Prior to 2003, these additional capital expenditures at Columbia were funded through the Columbia Net Billing Agreements, without borrowings by Energy Northwest. Since 2003, Energy Northwest has funded some or all of its additional capital expenditures at Columbia through the issuance of Electric Revenue Bonds.

In fiscal year 2011, Energy Northwest spent $109.9 million on capital improvements at Columbia. Energy Northwest spent approximately $87.6 million in fiscal year 2012 and expects to spend approximately $50.4 million in fiscal year 2013. The capital improvements at Columbia are expected to include plant license extension, responding to Fukushima impacts, installation of a new radio system, installation of new turbine vibration monitors, replacement of the radiation monitors, installation of new control rod blades, replacement of control rod drive valves and piping; and replacement of various pieces of equipment. Certain of the cost of these capital improvements in fiscal years 2012 and 2013 will be financed by previously issued Columbia Electric Revenue Bonds, and the Series 2012-D Bonds.

Nuclear Regulatory Commission Actions

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

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

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

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

To monitor these seven cornerstones, the NRC 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 First Quarter of 2012, the reactor safety and radiation safety cornerstones had only Green findings. All performance indicators were also Green. The Safeguards (Physical Protection) cornerstone information was made publically available on a limited basis starting July 1, 2012.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary at www.nrc.gov. As of July 1, 2012, the Safeguards (Physical Protection) cornerstone performance indicators and inspection findings were 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 (baseline) inspection 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.

As of May 15, 2012, the NRC's Regulatory Oversight Process Summary lists 87 plants, including Columbia, in the Licensee Response Column, 12 plants in the Regulatory Response Column, three plants in the Degraded Cornerstone Column, one plant in the Multiple/Repetitive Degraded Cornerstone Column and no plants in the Unacceptable Performance Column. Because of Columbia's position in the Licensee Response Column, the NRC is currently planning to conduct only baseline inspections.

Energy Northwest discovered some issues related to emergency planning during a July 2011 self-evaluation. Energy Northwest completed a thorough root cause evaluation and promptly implemented corrective actions. On July 26, 2012, Energy Northwest received a Baseline Inspection Report from the NRC, based on an NRC inspection at Columbia from October 2011 through June 2012. This report characterized the issues as two preliminary White findings. The NRC noted in the report that the conditions surrounding the White findings were previously corrected and were not indicative of current plant performance. The NRC currently plans to issue a final determination on these findings within 90-days of their July 26, 2012, report. Based on this determination, Columbia could move from the Licensee Response Column to either the Regulatory Response Column or the Degraded Cornerstone Column. A change in the NRC Column designation could result in increased NRC oversight and costs.

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 power plants. All United States utilities that operate commercial nuclear power plants are INPO members. INPO conducts plant evaluations of all United States plants, including Columbia, approximately every two years.

INPO completed a peer evaluation in October 2010 of Columbia's performance from October 2008 through September 2010. The evaluation found plant performance is acceptable and noted a number of strengths and accomplishments, as well as areas for improvement. Improvement areas include human performance, leadership and equipment reliability. Initiatives were put in place to improve performance following the peer evaluation. Energy Northwest's Excellence in Performance initiative was then put in place in 2011 to help further implement these improvements. See "Management Discussion of Operations."

World Association of Nuclear Operators

Energy Northwest is a member of the World Association of Nuclear Operators ("WANO"), a nonprofit organization that works to unite every company and country with an operating commercial nuclear power plant to achieve the highest possible standards of nuclear safety. WANO works directly with its members to help operators communicate effectively and share information openly. WANO is based in London, England, and has regional centers in Atlanta, Moscow, Paris and Tokyo, and its policies and programs are established on a global level. One of these programs is the peer review, which helps members compare their operational performance against standards of excellence through an in-depth, objective review of the operations by an independent team. Since 1992, WANO has conducted 496 operating station peer reviews in 34 countries/areas, including at least once at every member. WANO expects to have a peer review every four years. During 2011, WANO conducted 39 operating plant peer reviews and 15 follow-up visits. Energy Northwest had its WANO evaluation in December 2006, and is expected to have its next WANO peer review in November 2012.

Permits and Licenses

Energy Northwest has obtained all permits and licenses required to operate Columbia, including an NRC operating license which originally expired in 2023. In May 2012, the NRC approved Columbia's license for another 20 years, which license will extend operation of Columbia to 2043. See "Nuclear Regulatory Commission Actions" above for a discussion of NRC inspection activities related to Columbia.

A site certification agreement for Columbia was executed with the State of Washington in 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. Energy Northwest submitted an application for renewal of Columbia's NPDES permit in November 2010. The current permit remains in effect until the replacement permit has been issued by the Energy Facility Site Evaluation Council. 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.

Potential Impacts to the U.S. Nuclear Industry and the Columbia Generating Station from the Earthquake and Tsunami at the Fukushima Daiichi Plants in Japan

Since the earthquake and tsunami of March 11, 2011, that impacted the Fukushima Daiichi Plant in Japan, the nuclear industry has been working to first understand the events that damaged the reactors and then look to any changes that might be necessary at U.S. nuclear plants. Of particular interest is the performance of the General Electric Boiling Water Reactor 3 with Mark 1 containment systems in Japan and their onsite used fuel storage areas.

Energy Northwest's Columbia Generating Station is a newer design, a Boiling Water Reactor 5, with a Mark 2 containment system. The Mark 2 system is a more robust containment design that integrates the suppression pool into the main steel and concrete reinforced primary containment structure surrounding the reactor vessel.

Columbia has multiple reactor cooling options to provide makeup water to the core and used fuel pool and also has backup power for these systems in the event offsite power is lost. Backup power sources include three diesel generators, as well as additional back-up battery systems that can power plant instrumentation (and steam driven pump controls) for a minimum of four hours each without re-charging. All of this equipment is designed and rigorously maintained and tested to strict performance standards to ensure it remains reliable for response during postulated events.

Following the events of September 11, 2001, the entire U.S. nuclear industry re-evaluated preparedness to respond to events beyond a plant's design basis, or where no offsite or onsite power was available. Columbia owns a portable diesel generator, which is capable of providing continuous recharging of the battery system. The generator is stored on site, and is used as back-up when the station's main diesel generators are being maintained. To bolster preparedness following September 11th, Columbia purchased a fire truck which is maintained onsite. The vehicle is a pumper truck, used as a portable pump, which can be used to send water through either existing piping or fire hoses into the reactor core and used fuel pool. Columbia has also initiated procurement of a back-up trailer-mounted diesel pump, with similar capabilities.

The NRC determined that the U.S. fleet of all reactor types is considered safe for continued operations. The NRC has formed a task force to perform a systematic and methodical review to see if there are any near-term or long-term changes that should be made to programs and regulations to further ensure protection of public health and safety. After the events at the Japanese plants are fully investigated and understood, there may be additional requirements promulgated for the current fleet of U.S. nuclear reactors.

On April 18, 2011, various organizations, including Northwest Environmental Advocates ("NWEA"), an activist group, submitted to the NRC an "Emergency Petition to Suspend All Pending Reactor Licensing Decisions" pending the investigation of lessons learned from the Fukushima Daiichi Plant. These license decisions include all pending proceedings for the consideration of applications for construction permits, new reactor licenses, combined construction permit and operating licenses, early site permits, license renewals, and standardized design certification rulemakings for nuclear reactors. Energy Northwest filed its response to NWEA's Petition, the only one naming Columbia, on May 2, 2011. On October 18, 2011, the NRC Licensing Board issued a decision on this proceeding denying the proposed contention submitted by NWEA on the grounds that it was premature. In October 2011, NWEA filed a motion to "reinstate" the Fukushima contention based upon the NRC's Staff Requirements Memorandum dated October 18, 2011, which accepted certain recommendations of the Fukushima Task Force. That motion was denied. In November 2011, NWEA appealed the October 18 Board decision to the NRC. In March 2012, the NRC denied the appeal. This was the last pending contention against Columbia's license renewal petition. The rejected contention challenged the environmental review for the Columbia license renewal application because it did not account for what NWEA characterized as new and significant environmental implications stemming from the NRC's Fukushima Near-Term Task Force Report. The NRC has consistently denied these petitions on the grounds that all post-Fukushima orders and actions will apply to all plants, regardless of their licensing status.

The NRC granted Columbia a 20-year license renewal on May 22, 2012, allowing Columbia to continue operations through 2043.

A NRC Near-Term Task Force Review of Insights from the Fukushima accident was published on July 12, 2011, that included 12 recommendations for improvements to U.S. reactors. On October 18, 2011, the NRC approved seven of the Task Force recommendations for implementation. Regulatory actions that focus on increasing the time reactors can be maintained safely without offsite power have been assigned a goal of completion in 24-30 months with the implementation of the remaining recommendations within five years. In March 2012, the NRC began issuing implementation orders for the initial regulatory actions. Energy Northwest expects that these orders will require various capital improvements to Columbia over the next several years.

On March 12, 2012, the NRC approved three post-Fukushima orders. These orders encompass several requirements including: (1) developing, implementing, and maintaining guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool cooling capabilities following an extreme event beyond a plant's design; (2) plants with Mark I and Mark II containments must have a reliable hardened vent to remove decay heat and maintain control of containment pressure within acceptable limits following extreme events that result in the loss of active containment heat removal capability or prolonged station blackout; and (3) all operating reactors must install additional instrumentation in fuel storage pools that will allow trained personnel to assess pool water level during beyond design basis conditions.

For all three of these orders, all plants are required to submit their plans for implementing these requirements to the NRC by February 28, 2013, and complete full implementation no later than two refueling cycles after submittal of a licensee's plan or December 31, 2016, whichever comes first. Additionally, periodic status reports must be provided to the NRC so they can monitor progress in implementing the orders.

In addition to the three orders, also on March 12, 2012, the NRC issued a request for information that includes the following:

(1) All plants must perform and provide the results of a re-evaluation of the seismic and flooding hazards at their sites using present-day NRC requirements and guidance, and identify actions that are planned to address vulnerabilities. The results will determine whether additional regulatory actions are necessary (e.g., ordering plant modifications).

(2) Plants were requested to develop a methodology and acceptance criteria and perform seismic and flooding walkdowns. Any performance deficiencies identified would be addressed by the site's corrective action program.

(3) Finally, all plants were requested to assess the ability of their current communications to perform under conditions of onsite and offsite damage and prolonged loss of alternative current (AC) electrical power. Licensees also were requested to assess the plant staffing levels needed to respond to a large-scale natural event to implement strategies contained in the emergency plan.

Depleted Uranium Enrichment Program

In May 2012, the Executive Board of Energy Northwest approved participation in a depleted uranium enrichment program (the "Program") to provide fuel for the Columbia Generating Station. The Series 2012-E (Taxable) Bond proceeds will finance a portion of the cost of the Program. Under the Program, the U.S. Department of Energy ("DOE") has agreed to provide approximately 9,082 metric tons of depleted uranium hexafluoride ("Uranium Tailings") at no cost to Energy Northwest. The Uranium Tailings will be physically transferred from DOE ownership to the Paducah Gaseous Diffusion Plant ("PGDP") in Paducah, Kentucky where the Uranium Tailings will be enriched to a level necessary for fabrication into commercial nuclear fuel (the Uranium Tailings as so enriched, the "Enriched Uranium"). The PGDP is on land leased from DOE to the United States Enrichment Corporation ("USEC") and is operated by USEC. Bonneville sent Energy Northwest a letter of non-disapproval of the Program as required by the Columbia Project Agreement.

Energy Northwest approved participation in the Program to ensure an adequate and secure supply of fuel for Columbia, to minimize exposure to fluctuations in market prices and to procure fuel for Columbia at significant savings compared to current and expected market prices. Although Energy Northwest could use the entire amount of Enriched Uranium for Columbia's fuel needs through 2038, in order to improve the economic value of the Program and minimize risks, Energy Northwest has agreed to sell a portion of the Enriched Uranium and the value of separative work units (which is the process by which the assay or weight of the natural uranium is increased) to the Tennessee Valley Authority ("TVA") with deliveries beginning in 2015.

In May 2012, Energy Northwest and DOE entered into an agreement ("DOE Agreement") for the transfer of Uranium Tailings and the storage of the Enriched Uranium. The DOE Agreement terminates on December 31, 2022, when Energy

Northwest's expected need for storage ends. Energy Northwest will pay the actual cost, in an amount not to exceed $5 million, to DOE for delivery and storage over the term of the DOE Agreement. DOE made the first delivery of Uranium Tailings in May 2012 and expects to make further deliveries through April 2013.

DOE is responsible for the waste material after enrichment (newly created uranium tailings), which will be stored at its Paducah site. Energy Northwest will assume the risk of the loss of the Enriched Uranium during DOE storage, although Energy Northwest believes, based on DOE management at the site and the physical character of the storage cylinders, that the potential that the Enriched Uranium will be damaged or lost during storage is very low. If the DOE Agreement is terminated, Energy Northwest may terminate the USEC Agreement described below. If DOE delivers less than the expected amount of Uranium Tailings, Energy Northwest's obligations to USEC and TVA under the agreements described below would be reduced proportionately. If the DOE Agreement is terminated through no fault of the parties, and not due to judicial or congressional action that precludes DOE's performance, Energy Northwest must, within 45 days, provide DOE with a written plan for removal of Energy Northwest's Enriched Uranium, and use reasonable efforts to remove the Enriched Uranium as soon as possible. However, Energy Northwest may continue to store the Enriched Uranium at the DOE yard through the original term of the DOE Agreement if no other viable option exists. DOE's obligations are subject to the availability of appropriated funds and Energy Northwest understands that any claim by it for a DOE breach of the DOE Agreement may not be compensated.

Coincident with the DOE Agreement, Energy Northwest and USEC entered into an agreement (the "USEC Agreement") that obligates USEC to enrich the Uranium Tailings delivered from DOE. Energy Northwest expects to receive approximately 482 metric tons of Enriched Uranium. The USEC Agreement commits USEC to enrich the delivered Uranium Tailings in 2012 and 2013 and terminates on December 31, 2013, or the date on which all purchase and payment obligations are fulfilled. Energy Northwest's payments to USEC are tied to the amount of Uranium Tailings actually processed and are expected to be approximately $700 million. Deliveries and payments are expected to be twice each month. As of August 1, 2012, Energy Northwest has paid USEC $83,447,301 from draws under the Columbia Note, and is expected to make an additional $57,226,327 in payments from draws prior to August 23, 2012. See "PURPOSE OF ISSUANCE."

USEC has filed information with the Securities and Exchange Commission that raises various risk factors that could materially and adversely affect its business, results of operations and viability. To address these risks, Energy Northwest's obligation to deliver Uranium Tailings to USEC is conditioned on DOE's performance and delivery of Uranium Tailings under the DOE Agreement and Energy Northwest is obligated to pay USEC only after the Enriched Uranium is delivered to DOE for storage and its quality and quantity is validated by a third party. Energy Northwest is not making any advance payments to USEC. USEC is obligated to deliver to Energy Northwest title to the Enriched Uranium free of any liens by USEC's secured creditors. Energy Northwest may terminate the USEC Agreement if the DOE Agreement terminates for reasons other than Energy Northwest's breach or non-performance. Energy Northwest also may terminate the USEC Agreement if TVA ceases to supply electrical power to the PGDP. Energy supply is essential to the enrichment process and is a very large cost component of the enrichment process.

Coincident with the agreements described above, Energy Northwest and TVA entered into an agreement (the "TVA Agreement") for the sale and purchase of a portion of the Enriched Uranium delivered to Energy Northwest under the USEC Agreement for use by TVA. Energy Northwest will sell approximately two-thirds of the value of the Enriched Uranium produced from the Program to TVA. TVA is obligated to purchase specified quantities of the Enriched Uranium and separative work units at prices set forth in the TVA Agreement beginning in 2015 and ending in 2022. If the maximum is delivered to TVA under the TVA Agreement, TVA will pay Energy Northwest approximately $731 million and deliver Energy Northwest 1,650 metric tons of natural uranium. TVA has limited rights to delay deliveries and payment. If less than 482 metric tons of Enriched Uranium are produced under the USEC Agreement, Energy Northwest is required to sell to TVA a proportional share of what is actually produced after first retaining certain specified amounts for use at Columbia. Deliveries of the Enriched Uranium to TVA and transfer of title to TVA will occur at DOE's yard adjoining the PGDP. TVA is required to pay Energy Northwest on or before the date that Energy Northwest delivers the Enriched Uranium to TVA or to a third party on behalf of TVA. TVA cannot be excused from payment based on force majeure for Enriched Uranium actually delivered to TVA. If TVA wants to contest the quality of the Enriched Uranium, it must do so during 2012-2013 when the Enriched Uranium is produced. Either party may terminate the TVA Agreement for material breach by the other party. TVA may limit the amount of Enriched Uranium it purchases if it ceases to provide electrical power to USEC. As stated above, if TVA ceases to provide power to USEC, Energy Northwest may terminate the USEC Agreement and production under the Program will cease. If USEC acquires power from another source, however, Energy Northwest may, but is not required to, continue performance under the USEC Agreement. If TVA does not perform under the TVA Agreement, Energy Northwest may use the Enriched Uranium for Columbia or sell it to a third party.

On June 12, 2012, two members of the United States House of Representatives sent a letter to the Comptroller General of the United States Government Accountability Office ("GAO") requesting an investigation into recent actions taken by DOE including, among other things, DOE's uranium transfer under the DOE Agreement. In connection with the DOE Agreement, the members requested that GAO examine (i) the uranium market analysis utilized by DOE to assess the potential impact of its uranium transfer decision, (ii) whether DOE's uranium transfer decision includes sufficient safeguards to identify and/or prevent violations of the DOE Agreement, and (iii) the costs and legal basis for DOE's plan. To date, no such investigation has commenced. The outcome of any such investigation is unknown at this time.

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 Tailings, enrichment of the Uranium Tailings and fabrication of the Enriched Uranium in the form of uranium oxide pellets into finished fuel assemblies.

Fabrication services for the 2009 through 2015 reloads are provided pursuant to a contract with Global Nuclear Fuels – Americas, LLC. Columbia operates on a 24-month fuel cycle. A 24-month fuel cycle eliminates the need for refueling outages every year and results in increased average generation. 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. As discussed in the previous subsection, Energy Northwest recently approved the depleted uranium enrichment program. This new program as well as other purchases should be sufficient to supply fuel for Columbia through 2038.

Energy Northwest has a contract with DOE that requires 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 ($6.8 million for the 12 months ended June 30, 2011). To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating proposed sites for a repository. Although courts ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. 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 has completed the Independent Spent Fuel Storage Installation ("ISFSI") project, which is a temporary dry cask storage facility which is intended to store spent fuel 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. 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 $463.5 million (in 2011 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 $96.4 million (in 2011 dollars).

The decommissioning funding plan requires annual deposits to a fund through fiscal year 2039, the end of Columbia's 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 two years 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 June 30, 2012, totaled approximately $173.6 million. A separate fund has been established for site restoration. The balance of this fund as of June 30, 2012, totaled approximately $28.4 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 $12.595 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 $375 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 which is capable of generating 26 megawatts of electricity. 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 expired 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. On March 4, 2010, FERC issued a one-year extension to operate under the original license, which is indefinitely extended for continued operations, until a formal decision is issued by FERC and a new operating license is granted. Energy Northwest is still awaiting the new license and the plant will continue to run under its initial license until FERC's decision is rendered.

In fiscal year 2011, production at Packwood totaled 107,920 net megawatt hours, up 25.4% from the previous year due to increased water availability compared to fiscal year 2010. Fiscal year 2011 was the fourth highest generation in the last 18 years, while fiscal year 2010 was near the 46 year average of 90,500 net megawatts for Packwood. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs.

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 Packwood bonds, if any, whether or not the project is producing power or capable of producing power. For the period between October 2008 and October 2011, Public Utility District No. 1 of Snohomish County purchased all the base energy output of Packwood from the other participants and sold the excess on the open market. Energy Northwest currently is delivering power to the 12 participants and invoicing participants their share of the project's cost.

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. The 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 averaged 6.1 cents per kilowatt hour during fiscal year 2011.

In fiscal year 2011, Nine Canyon produced 264,740 net megawatt-hours of electricity compared to 226,730 net megawatt-hours in fiscal year 2010.

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, which 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 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 planned for the demolition and restoration of Project 1 and is now maintaining the site to support re-use activities. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with site maintenance activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements. The Project 1 Post Termination Agreement requires Bonneville to fund this site remediation plan for Projects 1 and 4. The cost for both sites' remediation is estimated at $22.5 million in calendar year 2009 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, which 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 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 3 in its entirety. In 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. In 1999, Energy Northwest transferred the Project 3 site properties and facilities (other than the Satsop combustion turbine site) to such local public agencies for purposes of economic development. In connection with that transfer, these local public agencies assumed responsibility for any required site remediation. 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 fourteenth year of operation.

FUTURE RESOURCES

Energy Northwest holds an option to lease approximately 16 acres at the Port of Kalama for a potential natural gas project. Development options for the natural gas power plant on this site are being assessed.

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:

<u>Energy Northwest v. United States of America, (No. 04-10C), EN-SNF1</u>. Energy Northwest filed an action against the United States of America (the "Government") in the U.S. Court of Federal Claims in 2004 for breach of contract for the Government's failure to dispose of spent nuclear fuel ("SNF") and high-level radioactive waste. In 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. On July 8, 2011, DOE and Energy Northwest filed a

Stipulation for Entry of Final Judgment in Favor of Plaintiff Energy Northwest. Energy Northwest received $48.7 million on August 29, 2011 to reimburse it for expenditures on SNF prior to September 1, 2006.

Energy Northwest v. United States of America, (No. 11-447C), EN-SNF2. Energy Northwest filed a second action against the United States of America (the "Government") in the U.S. Court of Federal Claims in July 2011 for its continuing breach of contract for the Government's failure to dispose of spent nuclear fuel and high-level radioactive waste and the additional damages Energy Northwest incurred or will incur between September 1, 2006, and June 30, 2012. The outcome of this matter cannot be predicted at this time.

Babcock and Wilcox Nuclear Power Generation Group, Inc. v. Energy Northwest (CV-11-5149-EFS). The contractor for the Columbia refueling improvements in 2011 filed a suit against Energy Northwest seeking approximately $50 million in damages. Energy Northwest has pending claims against the contractor of approximately $10 million. The lawsuit was stayed pending mediation of the dispute, and in May 2012, Energy Northwest and Babcock and Wilcox entered into a settlement agreement pursuant to which Energy Northwest agreed to accept the work on the condenser project and to pay slightly more than $18 million to settle the lawsuit and Babcock and Wilcox agreed to dismiss the lawsuit with prejudice. The Executive Board of Energy Northwest approved the settlement terms in May 2012, and the parties are working to complete the administrative details of the settlement.

LEGAL MATTERS

The approving opinion of Foster Pepper PLLC, Bond Counsel to Energy Northwest, as to the legality of the Series 2012-D/E Bonds will be in substantially the form appended hereto in Appendix D-1—"PROPOSED FORM OF OPINION OF BOND COUNSEL FOR THE SERIES 2012-D/E BONDS." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the status of the interest on the Series 2012-D/E Bonds for federal income tax purposes will be in substantially the form appended hereto in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2012-D/E BONDS."

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 made, 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 will assume the continued obligations of Bonneville, and performance by Bonneville of its obligations under, the Net Billing Agreements and Assignment Agreements, and such opinion will 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 will 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 OPINION OF BOND COUNSEL FOR THE SERIES 2012-D/E BONDS."

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 Columbia, 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 2012-D BONDS

At closing of the Series 2012-D Bonds, Special Tax Counsel is expected to deliver its opinion, 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, that interest on the Series 2012-D Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act") and Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Special Tax Counsel also is expected to deliver its opinion that interest on the Series 2012-D Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel is expected to observe that interest on the Series 2012-D Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. In rendering its opinion, Special Tax Counsel will rely on the opinions of Bond Counsel as to the validity of the Series 2012-D Bonds and the due authorization and issuance of the Series 2012-D 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 FOR THE SERIES 2012-D/E BONDS."

To the extent the issue price of any maturity of the Series 2012-D Bonds is less than the amount to be paid at maturity of such Series 2012-D Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2012-D Bonds), 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 2012-D 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 2012-D Bonds is the first price at which a substantial amount of such maturity of the Series 2012-D 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 2012-D Bonds accrues daily over the term to maturity of such Series 2012-D 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 2012-D Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2012-D Bonds. Beneficial Owners of the Series 2012-D Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2012-D Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2012-D Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2012-D Bonds is sold to the public.

Series 2012-D Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

Title XIII of the 1986 Act and the 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 2012-D Bonds. Energy Northwest and Bonneville have made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the Series 2012-D 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 2012-D Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2012-D Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring), or any other matters coming to the attention of Special Tax Counsel after the date of issuance of the Series 2012-D Bonds may adversely affect the value of, or the tax status of interest on, the Series 2012-D 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 expected to deliver its opinion that interest on the Series 2012-D Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, the Series 2012-D Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel is expected to express no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the 1986 Act or the Code or court decisions may cause interest on the Series 2012-D Bonds to be subject, directly or indirectly, to federal income taxation, to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. As one example, the Obama Administration recently announced a legislative proposal which for tax years beginning on or after January 1, 2013, generally would limit the exclusion from gross income of interest on obligations like the

Series 2012-D Bonds to some extent for taxpayers who are individuals and whose income is subject to higher marginal income tax rates. Other proposals have been made that could significantly reduce the benefit of, or otherwise affect, the exclusion from gross income of interest on obligations like the Series 2012-D Bonds. The introduction or enactment of any such legislative proposals or clarification of the 1986 Act or the Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the Series 2012-D Bonds. Prospective purchasers of the Series 2012-D Bonds should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation and regarding the impact of future legislation, regulations or litigation, as to which Special Tax Counsel is expected to express no opinion.

The opinion of Special Tax Counsel is expected to be based on current legal authority, cover certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2012-D Bonds for federal income tax purposes. The opinion is not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, Special Tax Counsel cannot give and is not expected to give 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 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville will covenant, however, to comply with applicable requirements of the 1986 Act and the Code.

Special Tax Counsel's engagement with respect to the Series 2012-D Bonds will end with the issuance of the Series 2012-D Bonds, and, unless separately engaged, Special Tax Counsel will not be obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2012-D 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 2012-D 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 2012-D Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

SERIES 2012-E (TAXABLE) BONDS

At closing of the Series 2012-E (Taxable) Bonds, Special Tax Counsel is expected to deliver its opinion, based upon an analysis of existing laws, regulations, rulings and court decisions, that interest on the Series 2012-E (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act or Section 103 of the Code. Special Tax Counsel is expected to express no opinion regarding any other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2012-E (Taxable) Bonds.

If Energy Northwest defeases any Series 2012-E (Taxable) Bond, such Series 2012-E (Taxable) Bond may be deemed to be retired and "reissued" for federal income tax purposes as a result of the defeasance. In that event, the Beneficial Owner of the Series 2012-E (Taxable) Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the Beneficial Owner's adjusted tax basis in the Series 2012-E (Taxable) Bond. See "DESCRIPTION OF THE SERIES 2012-D/E BONDS—DEFEASANCE."

CIRCULAR 230 DISCLAIMER

Investors are urged to obtain independent tax advice regarding the Series 2012-E (Taxable) Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2012-E (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 2012-E (Taxable) Bonds.

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2012-E (Taxable) Bonds.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's, a business unit within Standard & Poor's Financial Services LLC, a subsidiary of The McGraw-Hill Companies, Inc. ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2012-D/E Bonds the ratings of Aa1, 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 Series 2012-D/E 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 Series 2012-D/E Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the Series 2012-D/E Bonds from Energy Northwest and to make a bona fide public offering of such Series 2012-D/E Bonds at not in excess of the public offering prices (or yields corresponding to such prices) set forth on the inside cover page of this Official Statement. The aggregate Underwriters' compensation under the contract of purchase for the Series 2012-D/E Bonds is $2,618,890. The Underwriters' obligations are subject to certain conditions precedent contained in the contract of purchase, and they will be obligated to purchase all of such Series 2012-D/E Bonds being sold under the contract of purchase if any such Series 2012-D/E Bonds are purchased.

The Series 2012-D/E Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such Series 2012-D/E 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 Series 2012-D/E Bonds.

Citigroup Inc., parent company of Citigroup Global Markets Inc., one of the underwriters of the Series 2012-D/E Bonds, has informed Energy Northwest and Bonneville that it has entered into a retail brokerage joint venture with Morgan Stanley. As part of the joint venture, Citigroup Global Markets Inc. will distribute municipal securities to retail investors through the financial advisor network of new broker-dealer, Morgan Stanley Smith Barney LLC. This distribution arrangement became effective on June 1, 2009. As part of this arrangement, Citigroup Global Markets Inc. will compensate Morgan Stanley Smith Barney LLC for its selling efforts with respect to the Series 2012-D/E Bonds.

The Underwriters have provided the following information to Energy Northwest for inclusion in this Official Statement. The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Certain of the Underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various investment banking services for Energy Northwest and Bonneville, for which they received or will receive customary fees and expenses. In the ordinary course of their various business activities, the Underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve securities and instruments of Energy Northwest and Bonneville.

Merrill Lynch, Pierce, Fenner & Smith Incorporated, an Underwriter of the Series 2012-D/E Bonds, is an affiliate of Bank of America, N.A., which has extended credit to Bonneville in unrelated transactions and has entered into the Columbia Loan Agreement with Energy Northwest discussed under "PURPOSE OF ISSUANCE."

Citigroup Energy, Inc., an affiliate of Citigroup, Inc., has entered into a power sales contract with Bonneville.

Certain affiliates of Goldman, Sachs & Co. and Energy Northwest are trading counterparties.

CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934 ("Rule 15c2-12"), Energy Northwest and Bonneville will enter into a Continuing Disclosure Agreement, to be dated the date of delivery of the Series 2012-D/E Bonds, for the benefit of the owners and beneficial owners of the Series 2012-D/E 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 timely notices of the occurrence of certain enumerated events with respect to the Series 2012-D/E Bonds. Energy Northwest Annual Information is to be provided not later than 180 days after the end of Energy Northwest's fiscal year, commencing with the fiscal year ended June 30, 2012. The Bonneville Annual Information is to be provided not later than 180 days after the end of the Federal Columbia River Power System fiscal year, commencing with the fiscal year ended September 30, 2012. The Annual Information and notices of aforesaid enumerated events will be filed by Energy Northwest with the Municipal Securities Rulemaking Board (the "MSRB"). Currently, the information filed with the MSRB is available to the public without charge through its Electronic Municipal Market Access system ("EMMA"). Energy Northwest has not failed to comply with all previous undertakings for the Net Billed Bonds with respect to Rule 15c2-12 in any material respect in the preceding five years. However, Energy Northwest failed to file its fiscal year 2011 financial statements by specific reference and on time under its previous undertakings with respect to Rule 15c2-12 relating to its Nine Canyon Wind Project bonds. Such fiscal year 2011 financial statements were timely filed under the undertakings for the Net Billed Bonds and were included in the official statement relating to its Wind Project Revenue Refunding Bonds, 2012 that was filed with EMMA on April 4, 2012. Energy Northwest has since amended its filing of such 2011 financial statements to include its Nine Canyon Wind Project bonds. In addition, for such Nine Canyon Wind Project bonds, although the "Other Purchasers" information was not updated by Energy Northwest each year, each "Other Purchaser" has filed their annual financial statements on EMMA. In addition, Bonneville has not failed to comply with all previous undertakings with respect to Rule 15c2-12 in any material respect in the preceding five years; however, Bonneville has not included in its reports an update of the table of Operating Federal System Projects for Operating Year 2013 (contained in Appendix A under "POWER SERVICES—Operating Federal System Projects for Operating Year 2013"), as provided under certain (but not all) of its previous undertakings. The information in such table does not vary substantially from year to year. On August 8, 2012, Bonneville filed a supplement to its reports for the previous five years to include Operating Federal System Projects tables for Operating Year 2008 through Operating Year 2013. 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 AGREEMENT."

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 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 Electric Revenue Bond Resolutions, the Prior Lien 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 Series 2012-D/E Bonds, the basic agreements securing the Series 2012-D/E Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Electric Revenue Bond Resolutions, the Prior Lien Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the 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 Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the Series 2012-D/E Bonds is to be construed as a contract with the holders of such Series 2012-D/E 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/ Jeffrey Windham
Authorized Officer

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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 August 15, 2012, furnished by the Issuer (the "Official Statement") with respect to its Columbia Generating Station Electric Revenue Bonds, Series 2012-D and Series 2012-E (Taxable) (collectively, the "2012-D/E Bonds"). (The Columbia Generating Station is described in the Official Statement under "ENERGY NORTHWEST." The Columbia Generating Station and Energy Northwest's Project 1 and Project 3 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 2012-D/E 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 1,150 megawatts. (Although the rated capacity of Columbia Generating Station is 1,150 megawatts, Bonneville assumes 1,130 megawatts for long-range planning purposes.) 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 energy output in the current operating year 2013 of about 10,585 annual average megawatts (defined below) under median water conditions and about 8,586 annual average megawatts under low water conditions. (Bonneville's "Operating Year" runs from August 1 through July 31. By contrast, its "Fiscal Year" runs from October 1 through September 30.) (Annual average megawatts are the number of megawatt-hours of electric energy used, transmitted, or produced over the course of one year and each annual average megawatt is equal to 8,760 megawatt-hours.)

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, owns, operates, and maintains a high voltage transmission system (the "Federal 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, owners of generation projects, and power marketers. Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada, northern Utah, 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") at wholesale, meaning for resale by the utilities to end-use consumers in the Region. Bonneville also has contracts to sell power for direct consumption to several Federal agencies and a small number of companies ("Direct Service Industries" or "DSIs") located in the Region. 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," has resulted and is expected to continue to result in substantial payments by Bonneville to the exchanging utilities. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"), of which there are six. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

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—FERC and Non-discriminatory Transmission Access and the 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 Power Administration Fund (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 Columbia River Power System ("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 $830 million (including $70 million in principal payments in advance of due dates) in full and on time for Bonneville's fiscal year ended September 30, 2011 ("Fiscal Year 2011"). 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."

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. In the event of such a deferral, Bonneville is required to take action, for example by increasing rates or reducing costs, to assure that it has sufficient funds to repay the deferred amounts, with interest in future years.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Regional Power Sales

Bonneville sells electric power for Regional load requirements at rates that recover Bonneville's cost of providing such service. Bonneville sells power to Preference Customers and Federal agencies, in each case for their requirements, at "Priority Firm Preference Rates" (or "PF Preference Rates"). This is Bonneville's lowest-cost, statutorily-designated, power rate class. PF Preference Rates include separate rate schedules for specific types of service provided to Preference Customers and Federal agencies, and the related rate levels vary depending on the costs of such services. Bonneville provides DSI service at the Industrial Firm Power Rate (or "IP Rate"). For a discussion of Bonneville's currently applicable power rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2012 through 2013."

Power Sales to Preference Customers

Starting in Fiscal Year 2012, Bonneville began selling power service to its Preference Customers under new contracts for the 17 years from Fiscal Year 2012 through Fiscal Year 2028 ("Long-Term Preference Contracts"). Under these contracts, Bonneville provides electric power primarily to meet the Preference Customers' own "net requirements" in the Region. Net requirements are the customers' native loads (loads within their respective service territories) net of non-Federal System resources, if any, designated by a related customer as being used to serve its native loads. The three basic classes of power service that Bonneville provides under the Long-Term Preference Contracts are: (i) "Load Following" service, which includes the effective equivalent of "full requirements" service, meaning that Bonneville is responsible for meeting all of the customer's electric power loads, and "partial requirements" service, meaning that Bonneville is responsible for meeting all of the customer's electric power loads in the Region to the extent not met by electric power that the customer has otherwise committed to meeting its loads; (ii) Block Power, which is power provided in pre-determined amounts at pre-determined times to meet the customers' requirements; and (iii) Slice of the System (or "Slice"), which is a proportionate amount of power if, as, and when generated by the Federal System. Under the Long-Term Preference Contracts, Slice and Block are sold together as "Slice/Block." In aggregate, sales of the Slice component of Slice/Block under the Long-Term Preference Contracts represent about 26.9 percent of Federal System generation. By contrast, under the Preference Customer power sales contracts that expired at the end of Fiscal Year 2011 (the "Prior Preference Contracts"), Bonneville sold about 22.6 percent of the Federal System generation as Slice.

Each contract for Load Following service subjects the customer to a payment commitment under which it is required to pay for power tendered by Bonneville. If a customer's net requirements decline, however, the customer's purchase obligation from Bonneville is reduced commensurately. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their net requirements. If their net requirements decline, the Block portion is reduced first.

In contrast to the Prior Preference Contracts, the Long-Term Preference Contracts 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 will reflect, in general, the low, embedded costs of the existing Federal System. 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 "Tier 2 PF Rates" that recover the cost to Bonneville of acquiring the incremental electric power needed to meet Tier 2 Loads. For all Preference Customers purchasing power from Bonneville to meet Tier 2 Loads, such purchases will be integrated with purchases of power for Tier 1 Loads into a single power purchase. The purchase of power from Bonneville for Tier 2 Loads will be made on a take-or-pay basis for the specified amount of power.

Each Preference Customer's right to purchase power at Tier 1 PF Rates is determined based in part on the proportion that its net requirements bear to all Preference Customers' net requirements placed on Bonneville in a defined period prior to Fiscal Year 2011. The amount of power that a customer may purchase at Tier 1 PF Rates may change based on a number of events. For example, if the capability of Federal System resources, including the Columbia Generating Station, were to decrease, the amount of power a Preference Customer is to receive at Tier 1 PF Rates would decrease proportionately, although, in such a case, the ongoing costs of the related facilities (to the extent allocable to recovery in power rates) would nonetheless be recovered in Tier 1 PF Rates.

A key element of the Long-Term Preference Contracts and the "Tiered Rates" construct is the establishment of the basic features of a long-term rate design methodology ("Tiered Rates Methodology") for periodically determining the applicable PF Preference Rates throughout the term of the contracts. The Tiered Rates Methodology defines the costs that are to be allocated to Tier 1 PF Rates and Tier 2 PF Rates. The costs to be recovered under Tier 1 PF Rates include 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, limited possible amounts of power augmentation tied to the transition to the Long-Term Preference Contracts, power benefits to be provided to DSIs (if any), and Residential Exchange Program benefits. Under the Tiered Rates Methodology, a majority of revenues from Bonneville's sales of seasonal surplus (secondary) energy derived from Tier 1 Federal System resources are allocated to non-Slice Tier 1 PF Rates. (Slice/Block customers are to receive about 26.9 percent of the actual seasonal surplus (secondary) energy derived from Tier 1 Federal System resources and, therefore, do not receive the benefits of the revenues that Bonneville receives from its own sales of seasonal surplus (secondary) energy.) See "BONNEVILLE LITIGATION—Tiered Rates Methodology Record of Decision."

Under the Long-Term Preference Contracts, Preference Customers may define, before specified dates of election, the extent, if any, to which Bonneville will meet their Tier 2 Loads. Preference Customers have committed to place 22 annual average megawatts of Tier 2 Loads on Bonneville in Fiscal Year 2012 and 58 annual average megawatts in Fiscal Year 2013. Virtually all Tier 2 Load commitments for Fiscal Year 2014 will not be determined until the end of Fiscal Year 2012. Certain Preference Customers have notified Bonneville of their commitment to purchase Load Following service for Tier 2 Loads in the five fiscal years commencing with Fiscal Year 2015; however, the amount of Tier 2 Loads they will place on Bonneville will not be determined until the power rates proceeding applicable to the related fiscal year of Tier 2 service. Similar Tier 2 elections and advance notice to Bonneville are required in the five fiscal years beginning with Fiscal Year 2020, and the four fiscal years beginning with Fiscal Year 2025.

For a more detailed description of the Long-Term Preference Contracts, 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— Long-Term Preference Contracts."

Power Sales to DSIs

Bonneville is authorized to sell power to DSIs, but has no statutory obligation to do so. Coincident with developing the Long-Term Preference Contracts and Tiered Rates Methodology, Bonneville proposed to provide DSIs with economic benefits from low-cost Federal System power. Bonneville also proposed to recover the net cost of any DSI service from Tier 1 PF Rates. Bonneville currently interprets certain court rulings to require that any decision to provide DSI service be supported by an analysis demonstrating that the sale(s) will result in neutral or positive benefits to Bonneville. For this reason, Bonneville is unable to predict the level of service that it may make available to DSIs on a long-term basis. Bonneville currently has separate power sales agreements in effect with two DSIs. One sale provides for Bonneville to deliver 320 annual average megawatts to Alcoa, Inc. ("Alcoa"), an aluminum industry DSI, through August 31, 2012. Bonneville and Alcoa have been discussing entering into a new power sales agreement that would provide for Bonneville to deliver 300 annual average megawatts to Alcoa for the ten-year period ending September 30, 2022. The other DSI power sales agreement provides for Bonneville to sell about 20 annual average megawatts to Port Townsend Paper Corporation ("Port Townsend"), a non-aluminum industry DSI, through August 31, 2013.

Bonneville's service to DSIs is and has been the subject of litigation. 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, has issued two separate opinions that concluded that certain prior power sales by Bonneville to a DSI were not consistent with Bonneville's governing laws. See "BONNEVILLE LITIGATION—DSI Service Litigation."

Other Requirements Power Sales in the Region

While Bonneville is directed by law to do so under certain circumstances, Bonneville does not currently, nor does Bonneville expect to, sell Regional IOUs power to meet their net requirements loads until at least Fiscal Year 2020. See

"POWER SERVICES—Customer and Other Power Contract Parties of Bonneville's Power Services—Regional Investor-Owned Utilities."

Bonneville also sells Full Requirements power to eight Federal agencies to meet their loads, which Bonneville estimates are about 117 annual average megawatts in Operating Year 2013.

Loads and Resources Expectations

Bonneville expects that, in aggregate, its total power sales obligations will be about 8,436 annual average megawatts in Operating Year 2013 and will be about 8,452 annual average megawatts in Operating Year 2014. Of these loads: (i) the aggregate of Preference Customer, Federal agency, and DSI loads are forecast to increase from 7,453 annual average megawatts in Operating Year 2013 to 7,558 annual average megawatts in Operating Year 2014, and (ii) other Bonneville exports and intra-regional contract obligations are forecast to decrease from about 983 annual average megawatts in Operating Year 2013 to 894 annual average megawatts in Operating Year 2014. By contrast, Bonneville estimates that the Federal System resources will be able to produce, under certain assumptions of historically low water conditions, about 8,586 annual average megawatts in Operating Year 2013, increasing to 8,667 annual average megawatts in Operating Year 2014. (These estimates do not take into account power purchase and generating resource production, and reductions for "line losses," that is energy losses from transmitting power from generation sources to loads.) Bonneville has a minimal energy deficit in Operating Year 2013. Bonneville believes it will have adequate resources to meet this energy deficit utilizing a variety of options including several described in the paragraph below. See also "POWER SERVICES—Description of the Generation Resources of the Federal System" and the table entitled "Operating Federal System Projects for Operating Year 2013."

In September 2010, Bonneville issued its 2010 Resource Program. The program systematically evaluated Bonneville's need for new power resources in light of changes and potential changes in demands on existing system resources through Operating Year 2019. The Resource Program concluded that Bonneville will be able to meet its projected power sales and related commitments by undertaking an aggressive conservation implementation program and by relying on short- and mid-term energy purchases for certain periods of the year to cover potential peak demands and low hydro-generation periods. While Bonneville may make targeted, small-scale, long-term generating resource acquisitions, Bonneville does not believe that it will need to acquire substantial new, long-term resources apart from the conservation program efforts, through at least Operating Year 2019. 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—Bonneville's Resource Program and Bonneville's Resource Strategies."

Achieving the aggressive conservation program targets may mean substantial capital investment by Bonneville over the next several years, depending on the extent to which Bonneville or its customers fund the conservation activities.

Bonneville forecasts that annual conservation expenditures will average about $124 million per year in Fiscal Years 2012-2017. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program."

Consideration of a Prepaid Power Program

Bonneville has decided to proceed with a prepaid power program and issued a Request for Offers on August 14, 2012. This new program would enable one or more Preference Customers to provide lump sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028, the termination date of the Long-Term Preference Contracts. In return, participating Preference Customers would become entitled to future deliveries of a portion of electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments would be represented by fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments will not be for fixed blocks of electricity. The prepayment will entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then applicable power rates.

The program involves determining the amount of the prepayments and the amount of resulting credits through a competitive process in which Preference Customers will submit offers, which are bids to participate in the program. The program is sequenced so that Bonneville will know the prepayment amounts and credits in setting power rates for the Fiscal Year 2014–2015 rate period. Bonneville expects to expend the amounts it receives (if any) through the prepayment program by the end of the two-year rate period. Depending on the offers, if any, and other factors, Bonneville could accept up to roughly $500 million of prepayments in Fiscal Year 2013, resulting in approximately $4.35 million to $4.65 million of credits per month through Fiscal Year 2028. Offers are expected to be due in late November 2013. Bonneville is unable to predict the number of offers it will receive, the dollar amount of prepayments offered, the price of the offers or the amount of prepayment offers or price that Bonneville will accept. Depending on a variety of factors it is possible that Bonneville may seek to implement a power prepayment program in connection with future power rate proposals. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

2012 Residential Exchange Program Settlement

On July 26, 2011, Bonneville executed the 2012 Residential Exchange Program Settlement Agreement ("2012 Residential Exchange Program Settlement"). The 2012 Residential Exchange Program Settlement is intended to resolve long-standing litigation among Bonneville and numerous Regional parties over Bonneville's implementation of the Residential Exchange Program established by the Northwest Power Act. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program," and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation." The 2012 Residential Exchange Program Settlement has been signed by most Regional parties including all six Regional IOU customers, Preference Customers representing 89 percent of Bonneville's aggregate Preference Customer load, three state utility commissions, and several Preference Customer trade groups.

Under the 2012 Residential Exchange Program Settlement, Regional IOUs will receive a cash payment of approximately $182 million in Fiscal Years 2012 and 2013 (the cash payments reflect reductions to Residential Exchange Program benefits to recover prior fiscal year overpayments to Regional IOUs). The cash payments will gradually increase over the settlement term to approximately $259 million in Fiscal Year 2028. In addition, Bonneville will provide refunds to qualifying Preference Customers in an aggregate approximate amount of $77 million per year, from Fiscal Year 2012 through Fiscal Year 2019. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The 2012 Residential Exchange Program Settlement has been challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Bonneville Rates for the 2012-2013 Rate Period

Bonneville has established power and transmission rates for Fiscal Years 2012 and 2013 (the "2012-2013 Rate Period"), and FERC granted interim approval of such rates (the "2012-2013 Rates") shortly after Bonneville filed the rates and associated documentation with FERC in late summer of 2011. Final FERC approval of Bonneville rate proposals typically takes over a year from the date filed. The 2012-2013 Rate Period marks the beginning of the implementation of the Tiered Rates Methodology.

Bonneville continues to adhere to its policy and practice of establishing rates that achieve at least a 95 percent probability of meeting Bonneville's scheduled United States Treasury payment responsibility on time and in full over the entire two-year rate period. Bonneville's Treasury payments are payable from "net proceeds," meaning amounts in the Bonneville Fund remaining after payment of Bonneville's non-Federal payment obligations, including amounts, if any, under the Net Billing Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

With regard to tools to manage risks related to maintaining sufficient cash to pay all costs timely and in full, including scheduled payments to the United States Treasury, the power rates 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 net revenues; (ii) a rate level adjustment mechanism (the "Cost Recovery Adjustment Clause" or "CRAC") that allows power rate levels to be increased at the beginning of either of the two years of the rate period, in each case according to financial results as of the end of each of the prior fiscal years; and (iii) rate level adjustment mechanisms related to unexpected costs that may arise from ESA litigation relating to the Federal System. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2012 through 2013—Revenue Recovery Risk Mitigation" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Based on Fiscal Year 2012 third quarter results and estimates and forecasts of numerous factors including possible power prices for and the amounts of seasonal surplus (secondary) energy sales, the CRAC will not trigger in Fiscal Year 2012 for Fiscal Year 2013 rates based on the 2012-2013 Power Rates CRAC parameters.

A number of factors affected Bonneville's rate levels for the 2012-2013 Rate Period. These factors included (i) numerous assumptions regarding expected financial reserves as of the beginning of the 2012-2013 Rate Period, costs, expenses, and revenues (including forecasts of revenues from seasonal surplus (secondary) power sales and purchased power expense in Fiscal Year 2011 and during the 2012-2013 Rate Period), and (ii) the availability of certain risk tools (including CRAC). As a result, PF Preference Rate levels for the 2012-2013 Rate Period have increased over rates in effect for Fiscal Years 2010 and 2011 (the "2010-2011 Rates"). An exact comparison of the current power rate levels and past power rate levels is complicated because of the change to Tiered Rates. The average Tier 1 net cost represents a close approximation of the average PF Preference Rate under the 2010-2011 Rates. The average Tier 1 net cost in the 2012-2013 Rates represents about a 7.8 percent increase over average PF Preference Rates in the 2010-2011 Rates, an increase from approximately $26.82 per megawatt hour to $28.90 per megawatt hour. (The foregoing power rate levels exclude transmission charges to deliver the power to the customers.) Bonneville is offering two new power products at Tier 2 PF Rates for the 2012-2013 Rate Period – a short term rate and a load growth rate. The short term rate is $46.48 per megawatt hour in Fiscal Year 2012 and $48.69 in Fiscal Year 2013. The load growth rate is $48.63 per megawatt hour in Fiscal Year 2013, the only year with loads to which this rate applies. See "—Regional Power Sales—Power Sales to Preference Customers" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Long-Term Preference Contracts" for additional discussion about Tier 2 PF Rates and Tier 2 Loads.

The IP Rate level established for DSI service in the 2012-2013 Rate represents an increase of 5 percent over such rates in the 2010-2011 Rate Period: from approximately $34.59 per megawatt hour (excluding transmission charges) to $36.32 per megawatt hour (excluding transmission charges). The IP Rate is a rate for power that is provided to DSIs in the same amount all hours of all days. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2012 through 2013—DSIs."

Bonneville's transmission rates and the two required ancillary services rates for the 2012-2013 Rate Period remain unchanged from the 2010-2011 Rate Period. The wind balancing service rate, now referred to as the Variable Energy Resource Balancing Rate, decreased by 4.7 percent from the prior rate period, due primarily to greater efficiencies in integrating renewable resources into Bonneville's balancing area authority. See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

Bonneville began conducting workshops in March 2012 related to the upcoming combined power and transmission rate case for the two fiscal years beginning October 1, 2013 (the "2014-2015 Rate Period"). Bonneville plans to release the initial proposal for the 2014-2015 Rate Period in November 2012 and submit the final proposal to FERC by the end of July 2013.

Fiscal Year 2011 Financial Results

In Fiscal Year 2011, Bonneville made its scheduled United States Treasury payments on time and in full for the 28th consecutive year. Bonneville finished Fiscal Year 2011 with financial reserves of $1.01 billion, which is a decline of about nine percent from the prior fiscal year. Bonneville's net revenues increased $210 million from negative net revenues of $128 million in Fiscal Year 2010 to net revenues of $82 million in Fiscal Year 2011. Even though the Federal System experienced historic high water, sales of seasonal surplus (secondary) energy were lower than forecast because of very low market prices for seasonal surplus (secondary) energy. Low prices were caused by continued slow recovery of demand from the recession and by very low natural gas prices caused in part by the increasing availability of natural gas. In addition, a longer than expected outage at Columbia Generating Station and an unexpected outage at Grand Coulee Dam also contributed to lower than expected sales of seasonal surplus (secondary) energy. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2011."

Fiscal Year 2012 Expectations

Current analyses prepared outside of Bonneville (by the Northwest River Forecast Center) and relied on by Bonneville for planning purposes indicate a water supply forecast for the Columbia River basin, as of August 15, 2012 of 117 percent of the 30-year average for Fiscal Year 2012, as measured in terms of millions of acre feet of water or "MAF." 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.

Forecasts indicate continued low market prices for energy primarily due to the availability of energy from generators that use natural gas, the market price of which is at low levels. Bonneville expects that the lower-than-expected prices for secondary energy in Fiscal Year 2012 may adversely affect Bonneville's net revenues. Bonneville expects that Power Services will not meet the projection of $53 million in net revenues in Fiscal Year 2012 as forecasted in developing the 2012-2013 Rates. As of July 27, 2012, Bonneville estimated that financial reserves will be approximately $1.025 billion at the end of Fiscal Year 2012 as compared to $1.01 billion as of the end of Fiscal Year 2011. Financial reserves are composed of Bonneville cash, special investments held in the Bonneville Fund, and deferred borrowing from the United States Treasury and are affected by numerous factors including estimates of revenues and expenses for the year, increases or decreases in cash and cash equivalents related to the timing of collections and payments, capital expenditures, and principal and interest payments to the United States Treasury.

The foregoing estimates of fiscal year-end financial reserves and net revenues are based on highly uncertain variables and are subject to change.

Based on reserve levels in the Bonneville Fund and forecasts of revenues and expenses as of the end of the third quarter of Fiscal Year 2012, Bonneville believes that it will meet its Fiscal Year 2012 United States Treasury payment responsibilities on time and in full. Such belief is based on information and conditions observed in the third quarter of Bonneville's current fiscal year, which are subject to change.

Pending Retirement of Bonneville Power Administrator, Stephen J. Wright

On June 19, 2012, Stephen J. Wright, the Bonneville Power Administrator, announced plans to retire effective at the end of January 2013. Mr. Wright is the second longest serving Bonneville Power Administrator having assumed the position of Administrator on an acting basis in November 2000 and on a permanent basis in February 2002. The DOE has stated that it expects to begin the selection process for a new Bonneville Power Administrator in time to allow for a reasonable transition period prior to the retirement of Mr. Wright.

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 $2.5 billion (excluding "bookouts" from settlements other than by the physical delivery of power) 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 2011.

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 Federal 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 assumptions related to a low-water period on record for the Columbia River basin referred to as "Critical Water." 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 2013 (August 1, 2012 through July 31, 2013), the total Federal System would be capable of producing about 8,586 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes about 6,882 annual average megawatts from Reclamation and Corps hydro projects, about 1,007 annual average megawatts from Columbia Generating Station and other non-Federally owned resources (including co-generation, renewable, and non-utility generation projects), and about 697 annual average megawatts of firm energy from power purchases, exchanges, and other non-Federal transactions. See the table entitled "Operating Federal System Projects for Operating Year 2013."

Federal Hydro-Generation

The share of hydropower from Federally-owned hydroelectric projects and a small amount of power Bonneville has acquired from non-Federally-owned hydroelectric projects for Operating Year 2013 is estimated to be approximately 81 percent of Bonneville's total firm power supply. 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 2013."

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, described above, and seasonal surplus (secondary) energy, 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 new resources or augments to balance annual and seasonal firm energy needs, 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 planning purposes Bonneville estimates the amount of electric power it will need to meet loads above the expected Federal System firm power generated under 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 water conditions that reflect average circumstances. The energy that Bonneville has to market above Critical Water assumptions in a specified period is referred to as seasonal surplus (secondary) energy. The amount of seasonal surplus (secondary) 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 2013, the Federal System is estimated to generate seasonal surplus (secondary) energy of 1,329 annual average megawatts, assuming average water conditions (median water flows). In years with high water conditions (high water flows) the amount of seasonal surplus (secondary) energy could be as much as 2,517 annual average megawatts. In low water years, the amount of seasonal surplus (secondary) 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 of the Federal System to serve multiple statutory purposes. These purposes 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, 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 NOAA Fisheries biological opinions relating to the operation of the Federal System on the Columbia River and Snake River and tributaries and related court-ordered operations; (ii) the Fish and Wildlife Service biological opinions relating to operation of certain Snake River and Columbia River and tributary dams; and (iii) operations described in the Northwest Power and Conservation Council's Fish and Wildlife Program ("Council's Fish and Wildlife Program"). These measures include 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 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. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Other Power Resources and Contract Purchases

The balance of the Federal System includes, among other resources, power from the Columbia Generating Station, which has the largest capacity for energy production of the non-Federal resources of the Federal System. See Footnote 10 in the following table "Operating Federal System Projects for Operating Year 2013." 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 power purchases, exchanges, and other non-Federal transactions that provide roughly 697 annual average megawatts.

Operating Federal System Projects for Operating Year 2013

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 70-year record of river flows based on the period from 1929-1998 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 a given operating year by assuming that these historical water conditions 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 2013, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows (referred to as "Firm Energy"), Median Water Flows (referred to as "Median Energy"), and High Water Flows (referred to as "Maximum Energy"). 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.

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Operating Federal System Projects for Operating Year 2013[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	6,162	2,705	2,417	1,931
Hungry Horse	1952	4	366	151	104	82
Other Reclamation Projects(6)		16	125	182	171	126
1. Total Reclamation Projects		53	6,653	3,038	2,692	2,139
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph(7)	1955	27	2,535	1,329	1,243	1,109
John Day	1968	16	2,484	1,385	1,074	815
The Dalles w/o Fishway(8)	1957	24	2,034	966	812	610
Bonneville	1938	20	1,054	582	555	415
McNary	1953	14	1,127	721	644	494
Lower Granite	1975	6	930	405	290	192
Lower Monumental	1969	6	923	446	313	192
Little Goose	1970	6	928	422	299	194
Ice Harbor	1961	6	693	343	231	170
Libby	1975	5	579	276	218	177
Dworshak	1974	3	445	287	217	148
Other Corps Projects(9)		20	210	314	278	227
2. Total Corps Projects		153	13,942	7,476	6,174	4,743
3. Total Reclamation and Corps Projects (line 1 + line 2)		**206**	**20,595**	**10,514**	**8,866**	**6,882**
Non-Federally-Owned Projects						
Columbia Generating Station(10)	1984	1	1,130	878	878	878
Other Non-Federal Hydro Projects(11)		7	23	61	45	40
Other Non-Federal Projects(12)		11	28	89	89	89
4. Total Non-Federally-Owned Projects		**19**	**1,181**	**1,028**	**1,012**	**1,007**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(13)		**n/a**	**1,228**	**715**	**707**	**697**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**225**	**23,004**	**12,257**	**10,585**	**8,586**

Source: 2011 Pacific Northwest Loads and Resources Study, Bonneville, May 2011.

(1) Operating Year 2013 is August 1, 2012, through July 31, 2013. Discrepancies from the figures portrayed in the "2011 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 2011 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."

(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), Boise Diversion (1908), and Roza (1958).

(7) Chief Joseph is assumed to have slightly less generation under High Water Flows than Median Water Flows because of modeling assumptions that limit the expected generation from Chief Joseph in High Water Flow conditions.

(8) 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. Bonneville does not receive the output of the fishway project and it is not included in this table.

(9) 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).

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station will provide about 878 annual average megawatts in most refueling years and 1,030 annual average megawatts in non-refueling years. For Operating Year 2013, Columbia Generating Station is scheduled for a refueling and is expected to provide about 878 annual average megawatts; actual generation during the period will depend on performance of the project. This amount does not take into account any reductions in generation requested by Bonneville related to oversupply events. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System—Over-generation from High Water and High Wind."

(11) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Lewis County PUD's Cowlitz Falls Project (1994), and the Idaho Falls Power Bulb Turbine Projects (1982). Bonneville has acquired the output from the Idaho Falls Power Bulb Turbine Projects (1982) through September 30, 2021. If Bonneville's contracts to purchase power from any of these projects are renewed, those projects will be included in future studies.

(12) 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), Dworshak Small Hydro (2000), and Rocky Brook Hydro (1999) 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 (2001) wind project, a share from NWW Wind Power's Klondike Phase III (2007), the output from the White Bluffs solar project (2002), and a share of the City of Ashland's solar project.

(13) Bonneville Contract Purchases include contracts for power (including from non-Federal hydro projects) from both inside and outside the Region, including Canada. This also includes amounts of power returned from Slice customers for lost electric energy that occurs when electric power is transmitted.

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 most years, Bonneville sells substantial amounts of seasonal surplus (secondary) energy in market-based transactions. 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 believes that its revenues and expenses from market transactions are, and will be, subject to several key risks: (i) the availability of electric power supplies generally and 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.

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. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—2010 Dodd-Frank Act and Bonneville."

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

Bonneville's primary transacting counterparties are composed of four principal groups: Preference Customers, DSIs, Regional IOUs, and Market Counterparties. 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. 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."

Preference Customers

Bonneville's primary customer base is composed of Preference Customers which make long-term power purchases from Bonneville at cost-based rates to meet their native loads in the Region. Preference Customers are qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, and they are entitled by law to a 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 Preference Rate, for most of their loads. 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 Customer. 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 Customer. Bonneville sells power to certain large Preference Customers under market-type contracts other than for their own load requirements. 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 Preference Rate.

Direct Service Industrial Customers

Bonneville may, but is not required to, sell power to a limited number of DSIs within the Region for their direct consumption. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. Most of the aluminum industry in the Pacific Northwest has ceased to operate. Currently, Bonneville sells power to two DSIs in the aggregate amount of about 340 annual average megawatts.

Regional Investor-Owned Utilities

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 (meaning a Regional IOU's loads in the Region that are not met by the Regional IOU with its own designated power supplies) beginning in Fiscal Year 2020 if such service is requested not later than the end of Fiscal Year 2016. At the end of Fiscal Year 2016, the Regional IOUs will elect whether or not to purchase requirements power for Fiscal Years 2020 through 2028. Any requirements power provided by Bonneville under these contracts would be priced at the "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 Regional IOU long-term requirements 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, (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, and (v) the New Resources Rate bears additional costs of statutory rate protection afforded to Preference Customers, thereby likely making the rate uneconomic compared to market alternatives.

Bonneville provides firm power to the Regional IOUs under contracts other than long-term firm requirements contracts. Bonneville also sells substantial amounts of peaking capacity to Regional IOUs. Power sales to Regional IOUs are distinct from Bonneville's contracts implementing the Residential Exchange Program, as provided by statute. The Residential Exchange Program obligations, described herein, result in payments by Bonneville to participating utilities. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program" and "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—2012 Residential Exchange Program Settlement."

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

Bonneville has a large number of parties with whom it has commercial power-related arrangements that are not based on Bonneville's statutory obligations (as in the case of statutory load-meeting obligations to Preference Customers and Regional IOUs, and payment obligations under the Residential Exchange Program) or on long-term relationships that are based on prior statutory obligations (as in the case of DSIs). These counterparties include utilities located outside the Region, power marketers, and independent power producers. Transactions with these counterparties include, but are not limited to, arrangements for the purchase, sale and/or exchange of power, transmission, and related services.

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 are 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 Regional customer's request if the proposed export sale is at a higher, FERC-approved rate than the Regional 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 (secondary) energy from Bonneville and these transactions account for the greatest share of revenues from Bonneville's exports. The amount of seasonal surplus (secondary) 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 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.

Credit Risk

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. 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.

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

In connection with the historically high power prices and volatility in West Coast power markets in 1999-2001, FERC initiated three proceedings (collectively, the "West Coast FERC Proceedings") to address, under the Federal Power Act ("FPA"), whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. The West Coast FERC Proceedings and the problems experienced in West Coast power markets in 1999-2001 have also engendered litigation affecting Bonneville.

In the "California Refund Docket," FERC is examining whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC is examining whether and the extent to which power prices were "unjust and unreasonable." The California Power Exchange ("Cal-PX") (which filed for bankruptcy protection and has ceased operations) and the California Independent System Operator ("Cal-ISO") operated centralized auction energy markets where buyers could purchase power. Under the competitive power market structure that California established, Bonneville sold power to the Cal-ISO and the Cal-PX in 2000 and 2001. The California investor owned utilities − who were obligated by law to purchase from the Cal-ISO and Cal-PX markets – later sought refunds for their purchases at FERC. In litigation arising out of the California Refund Docket, the Ninth Circuit Court ultimately held, in September 2005, that Bonneville was not (under law in effect at the time) subject to FERC authority to order refunds. As a result of the court's ruling, the California Refund Docket cannot result in any FERC-ordered refund liability for Bonneville. On April 25, 2012, Bonneville received $73.8 million from Cal-ISO and Cal-PX for the principal amount of outstanding payment obligations to Bonneville for such sales during the 2000-2001 period that were withheld pending outcome of the litigation.

In light of the court ruling, three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric and Southern California Edison ("SCE"), and the California Attorney General on behalf of California Energy Scheduling Resources, a California state agency, filed separate breach of contract claims against Bonneville in the United States Court of Federal Claims ("Court of Federal Claims") in March 2007. Each claim seeks unspecified damages related to Bonneville's power sales into the Cal-PX and Cal-ISO markets. The California parties 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 and notwithstanding that FERC has no authority to order refunds against Bonneville for the related sales. The California parties also seek to recover pre-judgment and post-judgment interest and litigation costs. Bonneville estimates that the aggregate contract damages claimed by California parties in the Court of Federal Claims contract litigation arising out of the California Refund Docket are $50 million in specified damages plus an additional amount of unspecified damages. In October 2008, Bonneville filed answers to the various complaints. A trial on the liability issues concluded on August 2, 2010. The parties filed post trial briefs and closing arguments were held in February 2011. On May 2, 2012, the Court of Federal Claims issued an opinion in the trial on liability issues, holding that Bonneville had contracted to limit its power prices in its sales to the California parties and that Bonneville breached its contracts with the California parties by failing to pay refunds for amounts it retained in excess of the mitigated market clearing prices. A damages trial will be scheduled to determine the amount of damages in the event the parties cannot agree on the amount of damages.

In the second West Coast FERC Proceeding (the "Northwest Spot Market Docket"), FERC reviewed the extent to which power prices in the bilateral "spot market" in the Pacific Northwest were "unjust and unreasonable" in certain periods in 2000 and 2001. In November 2003, FERC concluded, among other things, that the prices during the relevant period were not unjust and unreasonable, that refunds should not be ordered, and that FERC would terminate the proceeding. 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. Based on the Ninth Circuit Court's decision that FERC lacked jurisdiction to order Bonneville to provide refunds under then-applicable law, Bonneville believes that the Northwest Spot Market Docket will not result in any refund liability to Bonneville. The Ninth Circuit Court's conclusions could, however, impact the breach of contract claim brought by the California parties in the Court of Federal Claims, as described above.

In the third West Coast FERC Proceeding (the "Show Cause Proceeding"), FERC issued "Show Cause Orders" to Bonneville and other West Coast power market participants in an investigation of whether they had manipulated prices in West Coast power markets in and after 2000. After further review, FERC dismissed the Show Cause Order with respect to Bonneville. Certain parties appealed the dismissal to Federal appellate court and FERC moved to dismiss the appeal. The Federal appellate court has not yet rendered a decision on the motion to dismiss the appeal.

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." 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."

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 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 Tier 2 PF Rates, which Bonneville expects will be higher than Tier 1 PF Rates. Bonneville has executed requirements agreements with four Regional IOUs for the period starting in Fiscal Year 2012, but no requirements power will be provided under these agreements until at least Fiscal Year 2020. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Power Sales."

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.

Long-Term Preference Contracts. Bonneville currently provides two basic types of service under the Long-Term Preference Contracts. These services are similar to those which Bonneville previously provided to Preference Customers: (i) Slice/Block service, which is an integrated power product combining Slice and Block, 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. 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 elected to purchase Slice/Block as the type of service they will receive under their Long-Term Preference Contracts. The remaining Preference Customers have elected to take Load Following service. In aggregate, sales of the Slice component of Slice/Block under the Long-Term Preference Contracts represent about 26.9 percent of Federal System generation. By contrast, Bonneville sold about 22.6 percent of the Federal System generation as Slice under the previous contract methodology. Preliminary forecasts for Fiscal Year 2012 indicate that loads met under Load Following service will be about 3,300 annual average megawatts. Loads met by Slice/Block service will be about 3,800 annual average megawatts in total, half of which is expected to be for the Block portion (1,900 annual average megawatts) and half of which is expected to be for the Slice portion (1,900 annual average 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 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. If a customer's net requirements decline, the customer's purchase obligation from Bonneville is reduced commensurately. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their net requirements. If their net requirements decline, the Block portion is reduced first.

Prior to Fiscal Year 2012 and the implementation of the Tiered Rates Methodology, when Bonneville augmented Federal System resources with market or other generating resources, the costs of these typically more expensive purchases were typically melded with the Federal System's low, embedded cost power, creating integrated power rates that masked both the real value of then-existing Federal System power and the incremental costs of meeting load growth. This cost-melding effect created incentives for Preference Customers to place incremental load growth on Bonneville and exposed Bonneville to certain associated risks relating to obtaining electric power to meet the incremental loads. To implement the policy directive of meeting incremental loads at rates reflecting the associated costs, the Long-Term Preference Contracts 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 will reflect, in general, the low, embedded costs of the existing Federal System. 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 Tier 2 PF Rates that recover the cost to Bonneville of acquiring the incremental electric power needed to meet Tier 2 Loads. Bonneville expects that Tier 1 PF Rates will be lower than Tier 2 PF Rates because the embedded cost of power of the existing Federal System, which will be allocated for recovery in Tier PF 1 Rates, will likely be lower than the cost of new resources obtained to meet Tier 2 Loads and allocated for recovery in Tier 2 PF Rates.

After certain adjustments agreed to by Bonneville in Fiscal Year 2011, the aggregate amount of power loads to be served at Tier 1 PF Rates has been set at 7,181 annual average megawatts, although such amount is subject to change in certain defined circumstances.

The aggregate amount of power available to be purchased at Tier 1 PF Rates may be expanded in certain limited circumstances. These include: (i) up to 250 average megawatts, if necessary, for new Preference Customers (the limit through Fiscal Year 2028), and (ii) 70 annual average megawatts for a potential sale to DOE. In addition, Bonneville's obligation to sell power at Tier 1 PF Rates will be reduced if and to the extent that specified existing Federal System resources, including the Columbia Generating Station, decline in capability.

With respect to the Tier 1 expansion reserved for new Preference Customers, a new Preference Customer, Jefferson County, Washington, Public Utility District No. 1 ("Jefferson County PUD"), will begin receiving service from Bonneville in July 2013 at Tier 1 PF Rates. Its Tier 1 commitment of 41 annual average megawatts is reflected in the aggregate 7,181 annual average megawatts referred to above. The Tier 1 commitment for Jefferson County PUD could be increased by about eight average annual megawatts if Bonneville, Jefferson County PUD, and Port Townsend, which is currently a DSI, agree that Jefferson County PUD will serve a portion of Port Townsend's loads. Bonneville cannot predict whether other potential public utilities will commence operation or become Preference Customers.

A key element of the Long-Term Preference Contracts is the establishment of the Tiered Rates Methodology for periodically determining the applicable PF Preference Rates throughout the term of the new contracts. Bonneville expects to employ two-year rate periods during the term of the Long-Term Preference Contracts. The Tiered Rates

Methodology defines the costs that will be allocated to Tier 1 PF Rates and Tier 2 PF Rates: Tier 2 PF Rates recover the costs of meeting Tier 2 Loads while Tier 1 PF Rates recover the costs of the Federal System generating facilities. The costs to be recovered under Tier 1 PF Rates include 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, power benefits to be provided to DSIs (if any), and Residential Exchange Program benefits. Under the Tiered Rates Methodology, a majority of revenues from Bonneville's sales of secondary energy derived from Tier 1 Federal System resources are allocated to non-Slice Tier 1 PF Rates. See "BONNEVILLE LITIGATION—Tiered Rates Methodology Record of Decision."

As noted above, 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 Tier 2 PF Rates that seek to recover the cost to Bonneville of acquiring the electric power needed to meet such Tier 2 Loads. For all Preference Customers purchasing power from Bonneville to meet Tier 2 Loads, such purchases will be integrated with purchases of power for Tier 1 Loads into a single power purchase, although the purchase of power by Bonneville for Tier 2 Loads will be made on a take-or-pay basis for the specified amount of power.

Bonneville provides several approaches for Preference Customers to define the extent, if any, to which Bonneville will meet their Tier 2 Loads. Bonneville provided the customers the ability to rely entirely on Bonneville to meet all such loads throughout the term of the contracts. Bonneville also allows 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 may require Bonneville to meet none, all, or designated portions of the customer's Tier 2 Loads. In addition, Bonneville allows 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.

Under the Long-Term Preference Contracts, Preference Customers have committed to the Tier 2 Loads they will place on Bonneville in the two fiscal years commencing with Fiscal Year 2012. Bonneville is obligated to meet 22 annual average megawatts of Tier 2 Loads beginning in Fiscal Year 2012, increasing to 58 annual average megawatts in Fiscal Year 2013. The commitments in Fiscal Year 2014 for virtually all Tier 2 Loads will not be determined until the end of Fiscal Year 2012. Preference Customers have committed Load Following service for Tier 2 Loads in the five fiscal years commencing with Fiscal Year 2015, but the amount of Tier 2 Loads they will place on Bonneville will not be determined until the power rates proceeding applicable to the related fiscal year of Tier 2 service. Similar Tier 2 elections and advance notice to Bonneville are required in the five fiscal years beginning with Fiscal Year 2020, and the four fiscal years beginning with Fiscal Year 2025.

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 existing generation resources; (v) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional loads; (vi) changes in the regulation of power markets at the wholesale and retail level; (vii) the overall load growth from population changes and economic activity within the Region; and (viii) evolving transmission system needs to provide ancillary services.

Bonneville's Authority to Add Resources. In order to meet the foregoing power sales and load 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: (i) electric power, including the actual or planned electric power capability of generating facilities; or (ii) 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. It addresses risks and uncertainties for the Region's electricity future and seeks a resource strategy that minimizes the expected cost of the Regional power system over the next 20 years. The Power Plan is revised by the Council approximately every five years. On February 10, 2010, the Council released its Sixth Northwest Power Plan (the "Sixth Power Plan"). 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."

According to the Sixth Power Plan, cost-effective energy efficiency could meet 85 percent of the new load over the next 20 years (about 5,900 of 7,000 average megawatts). This efficiency, combined with new renewable energy, could delay investments in new fossil-fuel power plants until future environmental legislation is clear and alternative low-carbon energy sources have matured in technology and cost. The resource strategy in the Sixth Power Plan includes five specific recommendations: (i) develop cost-effective energy efficiency aggressively — at least 1,200 average megawatts by 2015, and equal or slightly higher amounts every five years through 2030; (ii) develop cost-effective renewable energy as required by state laws, particularly wind power, accounting for its variable output; (iii) improve power-system operating procedures to integrate wind power and improve the efficiency and flexibility of the power system; (iv) build new natural gas-fired power plants to meet local needs for on-demand energy and back-up power, and reduce reliance on existing coal-fired plants to help meet the power system's share of carbon-reduction goals and policies; and (v) investigate new technologies such as the "smart-grid," new energy-efficiency and renewable energy sources, advanced nuclear power, and carbon sequestration.

Bonneville strongly supports the Sixth Power Plan's reliance on energy efficiency and renewable energy (primarily wind power) to meet the Region's future load growth and is committed to meeting Bonneville's 42 percent share of the Council's Regional conservation target. Bonneville's share equates to about 500 annual average megawatts of savings in aggregate over the five-year period of the Sixth Power Plan. Bonneville has already caused installation of 209 average megawatts of conservation through Fiscal Year 2011 and plans to achieve an additional 291 average megawatts of conservation within the five-year period. Achieving the conservation targets will help Bonneville manage future load-growth and minimize reliance on development of new generating resources in order to meet demand. See "—Bonneville's Resource Program and Bonneville's Resource Strategies—Electric Power Conservation."

Bonneville's Resource Program and Bonneville's Resource Strategies. In September 2010, Bonneville issued a "Resource Program" to evaluate whether Bonneville may need to acquire resources to meet its power supply obligations, primarily to customers under the Long-Term Preference Contracts. The Resource Program also supplies information to Bonneville's customers about resources available to meet their needs. The planning horizon for the Resource Program extends through Operating Year 2019. In addition to examining annual energy needs, the Resource Program assessed Bonneville's needs for monthly/seasonal heavy load hour energy, capacity needs for extreme weather events and hourly balancing reserves through Operating Year 2019.

The needs assessment showed that recent events, including the current economic recession, have reduced Bonneville's near-term resource needs. As a result, Bonneville expects to satisfy much of its expected supply needs through Operating Year 2013 with conservation and short-term power purchases from the wholesale power market. In Operating Year 2019, continued conservation efforts may not be sufficient in all load scenarios.

Bonneville's Resource Program states that the additional power supply Bonneville will need to secure, if any, after achieving conservation targets will depend in large part on the outcome of a number of uncertainties about loads that Bonneville may or may not serve: (i) Preference Customer choices of power supplier(s) for their Tier 2 Loads under the Long-Term Preference Contracts; (ii) long-term service to the DSIs; (iii) potential formation of new public or tribal utilities that can place load on Bonneville; (iv) increased load service to DOE; and (v) the growth of the wind power fleet in the Bonneville balancing authority area and the magnitude and source of supply for reserves to support wind power integration to the Federal Transmission System. In November 2009, Preference Customers made elections under their Long-Term Preference Contracts to supply about 75 percent of load growth in Fiscal Year 2012 through Fiscal Year 2014, while placing 25 percent on Bonneville during that period. These commitments to place a comparatively small amount of Tier 2 Loads on Bonneville have helped refine Bonneville's load placement expectations through Fiscal Year 2019.

The Resource Program identifies additional uncertainties that also could affect Bonneville's need for resources, including long-term Regional economic growth, long-term load growth, fish requirements that impact hydro-generation, success of conservation efforts, new regulatory requirements (carbon pricing), and continued availability of existing resources.

Short-Term Power Purchases. Bonneville's approach under the Long-Term Preference Contracts 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, to the extent that Bonneville assumes 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 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 low water 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 low water 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 high water 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.

Electric Power Conservation. Bonneville has conservation 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. Bonneville estimates that under its Fiscal Year 2012 conservation program, an annual average megawatt of energy savings will cost, on average, approximately $1.8 million, increasing to approximately $2.0 million in Fiscal Year 2013 and 2014. Bonneville estimates that it achieved new conservation savings of 71 annual average megawatts in 2009, 91 annual average megawatts in Fiscal Year 2010, and 118 annual average megawatts in Fiscal Year 2011. In Fiscal Year 2011, Bonneville achieved a higher level of conservation savings than planned and has decreased expected spending for conservation measures in Fiscal Years 2013 and Fiscal Year 2014 while remaining on target to achieve the expected total of 504 average megawatts of savings in aggregate over the five-year period Fiscal Year 2010 through Fiscal Year 2014. See "—Bonneville's Authority to Add Resources."

Bonneville's past policy had been to expense these conservation measures in the period incurred. Beginning in Fiscal Year 2012, rate case assumptions treat these conservation costs as capital. Current rate case assumptions amortize all capital conservation measures over a period of 12 years in order to match the expense with the period of benefit.

Renewable Energy. Bonneville presently purchases a total of approximately 67 annual 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 geothermal project. This project has not been built. It 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. Bonneville's expectation of the earliest date for commercial operation has been extended to October 1, 2015.

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 power into the Federal System; (2) Bonneville 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; and (3) Bonneville will continue during Fiscal Year 2012 to provide direct programmatic funding for research and development activities including long-term solar and wind data monitoring.

Residential Exchange Program

Implementing the 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 results in cash payments by Bonneville to exchanging utilities, which are required to pass the benefit of the cash payments through, in their entirety, to eligible residential and small farm customers.

Under the Residential Exchange Program, Bonneville is to "purchase" power offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology defining the costs that may be included in an exchanging utility's average system cost as 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 changes hands. Rather, Bonneville makes cash payments to each exchanging utility in an amount determined by multiplying the utility's eligible residential load by the difference between the utility's average system cost and Bonneville's applicable Priority Firm Exchange Rate (which is a version of the PF Preference Rate adjusted for the costs of statutory rate protection afforded to Preference Customers), 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—Federal System Statement of Revenues and Expenses."

Transition in the Provision of Residential Exchange Program Benefits. Following years of negotiation and litigation with various parties over implementing the Residential Exchange Program, in July 2011 Bonneville entered into the 2012 Residential Exchange Program Settlement with all six of its Regional IOUs and with Preference Customers representing a significant percentage of Bonneville's Preference Customers' aggregate load. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—2012 Residential Exchange Program Settlement" and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation." The 2012 Residential Exchange Program Settlement reconfigures the Residential Exchange Program, fixing the amount of aggregate program benefits the Regional IOUs receive from Fiscal Year 2012 through Fiscal 2028. As part of the settlement, the schedule of aggregate program benefits for the Regional IOUs begins at $259 million in each Fiscal Years 2012 and 2013, and increases over time to $286 million in Fiscal Year 2028, although in some years the actual cash payments will be lower than the program benefit levels.

Under the terms of the 2012 Residential Exchange Program Settlement, the parties agreed to a means by which Bonneville will correct the past overpayment of Residential Exchange Program benefits and the corresponding effects on Preference Customer rates (the overpayments of Residential Exchange Program benefits resulted in higher rate levels to Preference Customers than otherwise would have been the case). Past overpayments of Residential Exchange Program benefits to Regional IOUs will be recouped through offsetting reductions to Bonneville's future payments to Regional IOUs for Residential Exchange Program benefits. These recoupments or "Refund Amounts" will be approximately $77 million per year from Fiscal Year 2012 through Fiscal Year 2019. Thus, actual aggregate cash payments to the Regional IOUs will be about $182 million per year during the 2012-2013 Rate Period. The benefits of such Refund Amounts are passed directly on to Preference Customers in the form of credits on their power bills and in some cases cash payments. As of the end of Fiscal Year 2011, the un-recouped aggregate overpayment of Residential Exchange Program benefits was about $612 million. The recoupment period of Refund Amounts ends in Fiscal Year 2019. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—2012 Residential Exchange Program Settlement."

The 2012 Residential Exchange Program Settlement has been challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate, and enhance fish and wildlife resources to the extent they are affected by Federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife 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 compliance 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 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' operations & maintenance expense ("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 the aggregate of Direct Costs and Operational Impacts in Fiscal Year 2011 was about $650 million, with $422 million in Direct Costs and $228 million in Operational Impacts. Of the Operational Impacts in Fiscal Year 2011, $71 million was attributable to Replacement Power Purchase Costs and $157 million was attributable to Foregone Power Revenues.

Bonneville estimates that the aggregate of Direct Costs and Operational Impacts in Fiscal Year 2010 was about $802 million, with $393 million in Direct Costs and $409 million in Operational Impacts. Of the Operational Impacts in Fiscal Year 2010, $310 million was attributable to Replacement Power Purchase Costs and $99 million was attributable to Foregone Power Revenues.

The $29 million increase in Direct Costs from Fiscal Year 2010 to Fiscal Year 2011 was caused primarily by an increase in ESA-related expense arising from the 2008 Columbia River System Biological Opinion. See "—The 2008 Columbia River System Biological Opinion, the 2010 Supplemental Columbia River System Biological Opinion and Related Developments." The $239 million decrease in Replacement Power Costs from Fiscal Year 2010 to Fiscal Year 2011 was caused primarily by increased hydropower generation due to high water conditions. The $58 million increase in Foregone Power Revenues from Fiscal Year 2010 to Fiscal Year 2011 was also the result of increased hydropower generation due to high water conditions.

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, 13 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 only 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 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 implementation of the ESA with respect to the Federal System has been and is 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 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 annual 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 Fiscal Year 1995. Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council Program, discussed below. Bonneville is also providing funding under the funding agreements entered into with certain tribes and the states of Idaho, Montana, and Washington. See "—The 2008 Columbia River System Biological Opinion, the 2010 Supplemental Columbia River System Biological Opinion and Related Developments."

The 2008 Columbia River System Biological Opinion, the 2010 Supplemental Columbia River System Biological Opinion and Related Developments.

The 2008 Columbia River System Biological Opinion. On May 5, 2008, NOAA Fisheries issued its 2008 Columbia River System Biological Opinion (the "2008 Columbia River System Biological Opinion"), which addresses listed fish species affected by the operation of the hydroelectric dams on the Columbia and Snake Rivers. Among other things, the 2008 Columbia River System Biological Opinion is intended to address court-identified deficiencies arising from legal challenges to prior Columbia River System biological opinions. In general, the 2008 Columbia River System Biological Opinion adopts many of the measures that were implemented, were being implemented, and were proposed to be implemented under the prior Columbia River System biological opinions; however, the 2008 Columbia River System Biological Opinion also 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, an expanded habitat program, an expanded predation-management program, specific commitments and timetable for site-specific fish hatchery consultations and reforms, and proposed structural modifications to the hydro-system.

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.

Upon its release, a number of interests, including the State of Oregon, certain tribes, and certain environmental organizations, challenged the 2008 Columbia River System Biological Opinion in the United States District Court for the District of Oregon (the "Oregon Federal District Court"). See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River."

2010 Supplemental Columbia River System Biological Opinion. In April 2009, the administration of President Barack Obama initiated a review by NOAA Fisheries of the 2008 Columbia River System Biological Opinion. See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River." In September 2009, NOAA Fisheries presented the supplemental review, known as the "Adaptive Management Implementation Plan" (the "Management Plan"), to the Oregon Federal District Court. The Management Plan concludes that the 2008 Columbia River System Biological Opinion, as implemented under the Management Plan, "is legally and biologically sound." The Management Plan provides a series of short-term and longer-term contingent actions that would be implemented in the event of the occurrence of certain triggering events evidencing biological decline of the ESA-listed species. The short-term actions relate primarily to fish hatchery operations, fish predator management and fish harvest restrictions that can be implemented in less than a year. Longer-term actions include, among other items, alterations to fish predation management approaches, harvest practices, and hatcheries and hatchery practices, all of which would take more than one year to implement.

One long-term contingency action in the event there is a significant decline in the status of a Snake River species is a study of breaching one or more of the four lower Snake River dams of the Federal System. The 2008 Columbia River System Biological Opinion does not call for dam-breaching, which could interfere substantially with hydro-electric generation of the Federal System. Under the Management Plan, however, dam breaching is considered, although it is considered as a "contingency of last resort." It would be recommended to Congress (in the opinion of General Counsel to Bonneville, dam breaching of any of the Federal System dams would require Congressional enactment authorizing such action) only when the best scientific information available indicates dam breaching would be effective and is necessary to avoid jeopardizing the continued existence of the affected Snake River species taking into account the short-term and long-term impacts of such action. The Management Plan states that "it is reasonable to study breaching of lower Snake River dam(s) as a contingency of last resort because the status of the Snake River species is improving and the 2008 Columbia River System Biological Opinion analysis concluded that breaching is not necessary to avoid jeopardy. In addition, breaching lower Snake River dams would have significant effects on local communities, the broader region and the environment. It would require a major investment of resources and time. Therefore, any decision to seek the requisite congressional authority must be driven by the best available scientific information."

In June 2010, NOAA Fisheries issued a supplemental record and a decision to supplement the 2008 Columbia River System Biological Opinion with the Management Plan and certain other information addressing new and pertinent scientific information. As so supplemented, the 2008 Columbia River System Biological Opinion is referred to by NOAA Fisheries as the "2010 Supplemental Columbia River System Biological Opinion." A number of interests have challenged the 2010 Supplemental Columbia River System Biological Opinion in litigation. On August 2, 2011, the Oregon Federal District Court upheld the 2010 Supplemental Columbia River System Biological Opinion through 2013, but ordered that NOAA Fisheries issue a new or supplemental Columbia River System Biological Opinion by January 1, 2014 for the period 2014 through 2018 that identifies specific mitigation measures and provides better scientific support for the conclusion that those measures will avoid jeopardy than was provided for such period in the

2010 Supplemental Columbia River System Biological Opinion. The Oregon Federal District Court also ordered that NOAA Fisheries conduct spring and summer spill operations in a manner consistent with the annual spill orders that have been in effect since 2006. See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River."

The Columbia Basin Fish Accords. In concert with the development of the 2008 Columbia River System Biological Opinion, 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 in the spring of 2009 to assure long-term fish and wildlife funding with respect to the Federal System. In September 2009, the Federal agencies and the State of Washington signed an agreement addressing the Columbia River estuary. The foregoing 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.

Under the Columbia Basin Fish Accords, Bonneville has committed to make available roughly $994 million over the ten-year period ending September 30, 2018. Bonneville estimates that roughly 60 percent of its proposed funding commitments in the agreements would be for new work required for implementation of the 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 Columbia Basin Fish Accords provide funding assurances to implement many actions under the 2008 Columbia River System Biological Opinion to protect listed species under the ESA, the agreements also assure funding for other fish restoration efforts, including efforts under the Northwest Power Act.

Under certain of 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 ten years beginning April 2008. The 2009 agreement with Washington provides for similar commitments regarding the ESA. 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 Oregon Federal District Court. 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 agreements also provide a higher level of assured long-term funding, which was a concern raised by the court in reviewing past biological opinions.

Incremental Costs and Consequences of the 2010 Supplemental Columbia River System Biological Opinion. It is difficult to predict the aggregate increased cost to Bonneville that will arise from the 2010 Supplemental Columbia River System Biological Opinion (which incorporates the 2008 Columbia River System Biological Opinion). Many measures in the 2010 Supplemental Columbia River System Biological Opinion have been implemented, are currently being implemented, or would otherwise be implemented, including under the Columbia Basin Fish Accords. Certain measures involve long-term costs or expenses that are difficult to predict. Qualified by the foregoing and other uncertainties, Bonneville estimates that the 2010 Supplemental Columbia River System Biological Opinion and the Columbia Basin Fish Accords 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. The expected cost in Fiscal Year 2012 and 2013 of the 2010 Supplemental Columbia River System Biological Opinion was incorporated into Bonneville's power rates for the 2012-2013 Rate Period.

Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible changes in dam operations, under the ESA or other environmental laws, and whether the 2010 Supplemental Columbia River System Biological Opinion, will, given the challenges in litigation, be upheld by the courts for the period beyond 2013.

Willamette River Project Biological Opinion. In July 2008, NOAA Fisheries issued its Willamette River Project Biological Opinion (the "Willamette River Project Biological Opinion"), which addresses listed fish species affected by the operation of the hydroelectric dams located on various tributary rivers within the Willamette River basin in western Oregon for a 15-year timeframe.

In October 2010, Bonneville and the State of Oregon signed an agreement to permanently resolve longstanding wildlife mitigation issues associated with the Willamette River dams. This agreement addresses the Federal habitat protection and enhancement responsibilities under the ESA, Northwest Power Act, and other applicable laws related to the Willamette River Project. Bonneville agreed to provide funding for new land acquisitions, habitat restoration, and operations and maintenance costs for Fiscal Year 2011 through Fiscal Year 2025. Bonneville's total commitment under the settlement agreement is $144.1 million for that period, which includes an adjustment for inflation. In addition, Bonneville will continue funding Oregon Department of Fish and Wildlife's operation and maintenance costs for Fiscal Year 2026 through Fiscal Year 2043. Although this funding has not yet been set, Bonneville expects that negotiations will start at about $1.7 million per year.

Bonneville believes that the costs to achieve measures for stream flow, fish hatchery and habitat improvements, and structural changes at various dams could substantially increase its cost of power from these related dams. However, because these costs 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.

<u>Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville</u>. 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 authority 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 Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was about $99 million, $123 million, and $85 million in Fiscal Years 2009, 2010, and 2011, 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 low water 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.

<u>Council's Fish and Wildlife Program</u>. In 2000, the Council revised and adopted a 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. 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 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 2010 Supplemental Columbia River System Biological Opinion and the Willamette River Project Biological Opinion, the integrated program expense spending grew to $221 million in Fiscal Year 2011. Fiscal Year 2012 expenses and capital program investments are forecast to be $237 million and $60 million, respectively.

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 Rates for Fiscal Years 2012 through 2013

Bonneville completed the 2012-2013 Final Power and Transmission Rate Proposal and submitted it, together with supporting documentation, to FERC on August 1, 2011. FERC has provided interim approval to the 2012-2013 Rates. Final approval is still pending.

PF Preference Rates. Most of Bonneville's power sales are made to Preference Customers to meet their net requirements under specified types of service: Block/Slice and Load Following. These power products and services are provided at Bonneville's lowest, statutorily-designated, cost-based power rate class, the PF Preference Rates. PF Preference Rates in general reflect the cost of resources and other services provided to serve the Preference Customers' net requirements loads and Residential Exchange Program loads and, except with respect to the rate for Slice ("PF Slice Rate"), reflect the benefit of revenues from sales by Bonneville of seasonal surplus (secondary) energy. In the case of the Slice product, the participating customers receive a percentage share of the seasonal surplus energy of the Federal System and hence the PF Slice Rate does not reflect the revenues Bonneville receives from its marketing of seasonal surplus energy. The PF Slice Rate also does not incorporate the costs or 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 Preference Rate schedules, the applicable rate level depends on Bonneville's rate design and specific costs to provide the related service.

The average Tier 1 PF Rate (PF Preference Rate) is $28.90 per megawatt hour for the Fiscal Year 2012-2013 Rate Period, about 7.8 percent higher than in the Fiscal Year 2010-2011 Rate Period.

With respect to the Slice portion of Slice/Block service, the monthly PF Slice Rate is $1,952,169 per percentage point of Slice under the power rates for the Fiscal Year 2012-2013 Rate Period. (Slice customers do not pay a rate based on the quantity of energy provided; rather they pay a rate that is based on a proportion of Bonneville's costs of generation.) This represents an increase of about 4.8 percent from the Fiscal Year 2010-11 Rate Period. Unlike rates for Requirements service and Block service, PF Slice rates do not incorporate the costs or risks associated with power supply, secondary sales, and power purchase costs. These risks 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, PF Slice rates are not subject to the CRAC, described below, because PF Slice rates recover actual costs. For a description of Slice of the System, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Power Sales."

By law, the PF Preference Rate is also the basis for another important Bonneville rate: the Industrial Power Rate for service to DSIs. The PF Preference Rate, including the PF Slice Rate, and the Industrial Power Rate are also established to recover the net costs of the Residential Exchange Program. Preference Customers bear such costs in the PF Preference Rate, including the PF Slice Rate.

Residential Exchange Program. The 2012 Residential Exchange Program Settlement, executed by Bonneville in July 2011, was signed by most Regional parties including all six Regional IOU customers and Preference Customers representing 89 percent of Bonneville's aggregate Preference Customer load. With respect to the Residential Exchange Program, the 2012-2013 Rates provide for an average of $259 million per year in benefits to the residential and small-farm consumers of Regional IOUs and about $20 million per year to exchanging Preference Customers during the 2012-2013 Rate Period.

The PF Preference Rates do not reflect adjustments to Preference Customers' power bills and Residential Exchange Program payments to be made to correct for past overpayments of Residential Exchange Program benefits to Regional IOUs (Refund Amounts). While the benefit levels for Regional IOUs average $259 million per year, Bonneville is decreasing the actual payments to Regional IOUs under the Residential Exchange Program by the Refund Amounts, about an aggregate of $77 million per year during the 2012-2013 Rate Period, as part of the program to recoup past overpayments of Residential Exchange Program benefits. Likewise, Bonneville is crediting qualifying Preference Customers' power bills in like amounts. Thus, under the final rates Bonneville will make payments for Residential Exchange Program benefits to Regional IOUs of $182 million per year on average during the 2012-2013 Rate Period. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program" and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

DSIs. With respect to DSIs, the 2012-2013 Rates assumed that Bonneville would provide the DSIs with 340 annual average megawatts of service. Subsequent to the completion by Bonneville of the Final 2010-2011 Power and Transmission Rate Proposal, the Ninth Circuit Court issued an opinion holding that Bonneville must show benefits in its power sales to DSIs. Bonneville later entered into two contracts with DSIs under the IP Rate of $36.32 per megawatt hour (excluding transmission service). Bonneville entered into these contracts upon concluding that the DSI power sales will provide benefits to Bonneville. See "BONNEVILLE LITIGATION—DSI Service Litigation."

Revenue Recovery Risk Mitigation. The 2012-2013 Rates include a mix of financial risk management tools that Bonneville designed to meet Bonneville's policy of setting rates that have a 95 percent probability of recovering Bonneville's Federal payment obligations over the applicable rate period. The 2012-2013 Rates continue to employ a CRAC to enable Bonneville to increase power rate levels at the beginning of either of the years of the two-year rate period. The CRAC is designed to enable Bonneville to obtain up to an additional $300 million in revenues from non-Slice Preference Customers in the related fiscal year, subject to a variety of conditions. The CRAC did not trigger in Fiscal Year 2011 for Fiscal Year 2012.

The 2012-2013 Rates continue a modified version of the "National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment" or "NFB Adjustment" to enable Bonneville to increase power rate levels beyond the cap of $300 million in additional revenues that Bonneville could recover in a fiscal year under the CRAC to cover the costs of certain potential adverse events related to the litigation over the 2010 Supplemental Columbia River System Biological Opinion, should such events occur. Those 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 2012-2013 Rates also continue an "Emergency National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Surcharge" or "Emergency NFB Surcharge" to enable Bonneville to increase power rate levels at any time in the 2012-2013 Rate Period in order to recover certain costs that could arise from the litigation over the 2010 Supplemental Columbia River System Biological Opinion, provided that Bonneville determines that its United States Treasury payment probability has fallen below 80 percent for the fiscal year in which the costs arise. The NFB Adjustment did not trigger in Fiscal Year 2011 for Fiscal Year 2012 Rates and the Emergency NFB Surcharge has not triggered in Fiscal Year 2012, although the NFB Adjustment and Emergency NFB Surcharge remain available to Bonneville during the 2012-2013 Rate Period if the conditions triggering their use arise.

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 or "stranded." Stranded costs may arise where power customers are able, pursuant to 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 and 212 of the FPA. For a discussion of Order 888 and sections 211 and 212 of the FPA, as amended by EPA-1992, see "TRANSMISSION SERVICES—FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services."

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211 and 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 and 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 and 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 and 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 but must be balanced with them. 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. Transmission Services earned about $740 million in revenues from the sale of transmission and related services, or roughly 23 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 2011.

Bonneville's Transmission Services provides transmission service under its Open Access Transmission Tariff ("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, primarily for delivery of Federal power to their loads. Point-to-Point service is typically taken by power marketers, independent power producers, and certain large utility customers. Finally, Bonneville, as a partial owner of the northern portions of the 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 is, those that were in effect when Bonneville adopted open access in the mid-1990s. As these contracts expire, the service converts to Tariff services.

It is difficult to generalize as to a Preference Customer's cost of Network Integration service needed to effect various power transactions because the rate per megawatt hour of transmission depends on actual usage and thus can vary from day to day and customer to customer. Nonetheless, a useful point of reference for the proportion that power rates bear to transmission and ancillary services rates may be the cost borne by certain Preference Customers that purchase Full Requirements power from Bonneville. For example, in Fiscal Year 2011 a large Preference Customer that purchases very little transmission for its own resources paid Bonneville approximately $4.32 per megawatt hour for transmission service and approximately $28.90 per megawatt hour for electric power.

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System that is owned, operated, and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-Federal power resources. The Federal Transmission System is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 300 substations and other transmission 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 primary bulk transmission link between the Pacific Northwest and the Pacific Southwest. 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 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 actual operating transfer capability can vary (or reliability transfer capability) 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 Network, 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; 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 power 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 statutory provisions relating to reliability. Bonneville continually monitors the 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 operating transfer capability 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 the system's users, including Bonneville's Power Services. To assure that the system is adequate to meet transmission needs, Transmission Services evaluates system performance to determine whether or not to make transmission infrastructure investments.

Bonneville focuses its transmission infrastructure efforts on transmission projects needed to maintain reliability and new transmission projects 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, primarily wind generation, both inside and outside the Region. Bonneville's current transmission system investment plan calls for Bonneville to make investments in Fiscal Years 2012 through 2017 averaging about $604 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.

If a customer requests transmission service and Bonneville determines that additional facilities need to be constructed to accommodate the request, Bonneville may seek advance funding of its costs for the necessary investments from the customer seeking the transmission service. If the necessary facilities are integrated into Bonneville's Network, Bonneville returns, over time, to the customer the amounts it advanced for construction of the new facilities. Bonneville returns these amounts in the form of (i) credits against billings by Bonneville for firm transmission service purchased from Bonneville at established transmission rates or (ii) in some cases, cash payments to the generator or its assigns. The costs of these new facilities are allocated to Network service rates, thereby spreading the costs among all Network customers.

Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments will be about $40 million in Fiscal Year 2012 and $49 million in Fiscal Year 2013. It is possible that the amount of such credits could increase in future years depending on the development of new generation projects (particularly wind projects) that will require transmission service over the Federal Transmission System.

Bonneville also, where applicable and in a manner consistent with Bonneville's Tariff, may apply the "or" test to recover new transmission facility costs. Under the "or" test, Bonneville compares the "incremental cost" rate for transmission service to Bonneville's embedded cost rate, and charges the requesting customer the higher of the two rates. The application of the "or" test generally protects Bonneville's Network customers from costs they would otherwise bear due to the integration costs of the new facilities.

FERC has approved Bonneville's current planning process, commonly referred to as "Network Open Season," whereby Bonneville identifies which new transmission projects would be most effective based in large part on the extent to which customers, including developers of proposed new generation such as wind generation, are willing to execute long-term, creditworthy commitments for transmission service that require these new Network transmission system investments. Bonneville believes that this process assists Bonneville in assuring it will recover the costs of investing in related transmission facilities and help avoid stranded transmission investments.

Bonneville's transmission system investment plan is subject to change as Bonneville is unable to predict the cost of new investments for the integration of new generation or to meet customers' new transmission service requests, the amount that customers will actually commit to 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. For discussion of applicability of FERC's cost allocation methodology under Order 1000, see "—Bonneville's Participation in a Regional Transmission/Planning Organization."

With respect to Bonneville's lease-purchase program, Bonneville entered into a long-term, capitalized lease-purchase agreement with Northwest Infrastructure Financing Corporation ("NIFC") in 2003 for 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.

In June 2007, Bonneville entered into a master lease agreement with Northwest Infrastructure Financing Corporation II ("NIFC II") (amended and restated as of December 9, 2010) under which Bonneville entered into lease-purchase commitments to lease $90 million in aggregate Federal Transmission System replacements and improvements. In July 2012, the Port of Morrow, Oregon (the "Port") and NIFC II entered into an agreement pursuant to which NIFC II sold its interests in the NIFC II transmission facilities to the Port. Coincidentally, the Port and Bonneville executed a lease purchase agreement (the "Lease Agreement") under which the Port leased such facilities (the "Project") to Bonneville and pledged Bonneville's lease rental payments to the payment of debt service on approximately $85 million in bonds issued by the Port, having a fixed maturity of June 30, 2042. The Port used a portion of the proceeds from the sale of the bonds to fund the acquisition of the transmission facilities from NIFC II. The bonds are secured solely by the Port's pledge of Bonneville's lease rental payments under the Lease Agreement.

Subsequent to the entry into the NIFC II master lease arrangement Bonneville entered into four separate master lease agreements with Northwest Infrastructure Financing Corporation III ("NIFC III"), Northwest Infrastructure Financing Corporation IV ("NIFC IV"), Northwest Infrastructure Financing Corporation V ("NIFC V"), and Northwest Infrastructure Financing Corporation VI ("NIFC VI") under which Bonneville has entered into lease-purchase commitments for $528.7 million in aggregate Federal Transmission System replacements and improvements. Under these master lease arrangements, Bonneville's lease-purchase payments are pledged to the payment of the bank loans entered into by NIFC III, NIFC IV, NIFC V, and NIFC VI. Proceeds of the bank loans were used to fund the acquisition, construction, installation, and equipping of the leased facilities. Bonneville's lease payments are not conditioned on the completion, suspension, or termination of the related projects. The principal amounts associated with all of the bank loans described above are included in Federal System audited financial statements as "Non-Federal Debt" and the principal amounts associated with the 2012-D/E Bonds will be included in Federal System audited financial statements as "Non-Federal Debt." As part of Bonneville's annual budget submitted to Congress for Fiscal Year 2013, Bonneville forecast that expenditures from funds provided under lease-purchase agreements will average about $89 million annually over Fiscal Years 2012-2017. The budget forecasts are not binding on Bonneville and the actual value could differ, perhaps substantially, from such estimates depending on capital spending in such years and other factors.

FERC and Non-discriminatory Transmission Access and the 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 function. EPA-1992 amended sections 211 and 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 EPA-1992. Therefore, FERC may order Bonneville to provide others with transmission access over the Federal transmission system facilities. FERC also may 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 and 212 are to be established by Bonneville, rather than by FERC, and are 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 addition, with respect to Bonneville's ability to recover its transmission costs through its transmission rates, it is the opinion of Bonneville's General Counsel that the 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."

In 1996, FERC issued 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 regulated or jurisdictional utilities to adopt the tariff. Order 888 also included a reciprocity provision under which jurisdictional utilities must grant open access transmission services to non-jurisdictional (i.e., unregulated) utilities if the non-jurisdictional utility offers open access in return, either through bilateral contracts or by (i) submitting to FERC for its approval an open access transmission tariff that substantially conforms or is superior 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. FERC issued "Order 890" in February 2007, which further supported Order 888's aims, emphasizing increased transmission access and transparency and promotion of transmission utilization. Bonneville is a non-jurisdictional utility.

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."

Because Bonneville is a non-jurisdictional utility, FERC Orders 888 and 890 have limited applicability. Notwithstanding, since 1996, Bonneville has adopted terms and conditions for a non-discriminatory open access transmission tariff and has voluntarily filed its Tariff with FERC to obtain reciprocity status. Bonneville filed an Order 890 tariff on October 3, 2008. FERC approved most of Bonneville's Tariff in an order issued July 15, 2009, but denied reciprocity pending resolution of certain limited issues. Bonneville's subsequent request for rehearing was denied. After seeking public review and comment, Bonneville voluntarily filed a new Order 890 tariff with FERC on March 29, 2012 seeking reciprocity approval. Several parties filed protests to certain aspects of Bonneville's new Order 890 tariff, requesting that FERC deny reciprocity. Bonneville responded, requesting leave to answer and included its response in a filing on May 30, 2012.

On December 7, 2011, in response to complaints filed at FERC concerning Bonneville's Interim Environmental Redispatch and Negative Pricing Policies ("Interim Policies") issued on May 13, 2011, and pursuant to its authority under EPA-2005 and section 211A of the FPA, FERC ruled that Bonneville's Interim Policies did not provide for comparable transmission service. FERC ordered Bonneville to file, within 90 days of its ruling, tariff provisions addressing the comparability concerns raised in the proceedings. On March 6, 2012, Bonneville filed amended tariff provisions. The amended tariff provisions went into effect on April 1, 2012. Bonneville continues to offer open access transmission service pursuant to its initial Order 890 tariff as amended pursuant to FERC's December 7, 2011 ruling and continues to receive open access from other transmitting utilities despite its lack of reciprocity. Bonneville voluntarily filed its new Order 890 tariff on March 29, 2012, and expects to continue to update its tariff as appropriate to reflect changes FERC makes to the *pro forma* tariff. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System."

In April 1996, FERC issued "Order 889" and more recently, in October 2008, "Order 717," each setting forth the "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 provider do not obtain unfair market advantage by having preferential access to information regarding the transmission provider's transmission operations. Although Bonneville is not subject to Orders 889 and 717, non-jurisdictional utilities must adhere to it in order to obtain reciprocity. Therefore, in the 1990s Bonneville separated its transmission and power functions into separate business units. Bonneville continued to voluntarily adapt its operations to comply with FERC's standards of conduct provisions. It currently operates in accordance with the standards of conduct set forth in Order 717.

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 rate period. FERC approves and confirms Bonneville's transmission rates after a finding that such rates recover Bonneville's costs during the rate period, and are sufficient to make full and timely payments to the United States Treasury.

Bonneville proposed and FERC issued interim approval of Bonneville's final transmission, ancillary services and control area service rates for the two years beginning Fiscal Year 2012. All of the transmission rates and the two required ancillary services rates remain unchanged from the prior transmission rate period, Fiscal Years 2010-2011. Bonneville estimates that its transmission rates and the two required ancillary services for Network Integration service are about $4.32 per megawatt hour under the 2012-2013 Rates.

As did the prior rates, the 2012-2013 Rates include a rate for wind balancing services (now referred to as the Variable Energy Resource Balancing Rate) to recover the costs that Bonneville bears in integrating wind resources into the Federal System. This rate recovers the costs of the reserves described above. The Variable Energy Resource Balancing Rate averages about $5.69 per megawatt hour of wind generation, assuming wind energy production is about 30 percent of the installed capacity of wind generation. The rate is in addition to applicable rates for the transmission of power. For a discussion of wind energy integration, see "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System."

Bonneville's Participation in a Regional Transmission/Planning 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 functions. 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 were implemented. FERC decided that participation in RTOs is 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 a member of "ColumbiaGrid," a regional planning organization comprising eight western transmission owners with balancing authority areas in the Region. ColumbiaGrid is not an "RTO" under FERC policies since ColumbiaGrid has a relatively restricted scope of operations. ColumbiaGrid focuses on coordinating Regional transmission planning and expansion, assisting participating utilities in meeting their transmission planning reliability obligations, and operating an information system to provide power marketers and others with information about transmission system operations. It is possible that in the long run ColumbiaGrid would have increased operational control of the Region's 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.

Bonneville has entered into agreements to fund a proportionate share of the costs of making ColumbiaGrid operational and to assist ColumbiaGrid in efficient transmission planning and expansion in its service area. Bonneville's estimated expense associated with the foregoing and other existing arrangements with ColumbiaGrid continue to be about $3 million per year. Bonneville and the other participants in ColumbiaGrid continue to work on the development of ColumbiaGrid's operations.

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. Efforts to implement the results of this Joint Initiative are ongoing.

FERC has provided further regional transmission planning direction in its "Order 1000" issued on July 21, 2011. Order 1000 requires, among other things, that jurisdictional utilities participate in certain regional transmission planning processes and in regional and interregional cost allocation methodologies for transmission projects. Order 1000 by its terms does not apply to non-jurisdictional utilities, such as Bonneville, but FERC has strongly encouraged non-jurisdictional utilities to participate and comply. FERC, in Order 1000, stated that it will apply its reciprocity policy and that it might exercise its authority under section 211A of the FPA to require non-jurisdictional utilities' compliance with Order 1000's provisions if voluntary compliance is not forthcoming. FERC's reciprocity policy would allow jurisdictional utilities to deny open access transmission service under their *pro forma* tariff to a non-jurisdictional utility that has not adopted a tariff meeting FERC's open access policies, including Order 1000. The reciprocity policy has not been tested in court.

Bonneville supports regional transmission planning and increased interregional coordination as demonstrated by its participation in ColumbiaGrid. Bonneville believes, however, that certain provisions of Order 1000, mainly its cost allocation provisions, may conflict with Bonneville's statutory transmission system obligations and authority. Bonneville filed a request for clarification and rehearing on August 22, 2011, on these and other issues. Several other non-jurisdictional utilities filed similar clarification and rehearing requests.

FERC issued an order on rehearing and clarification, Order 1000-A, on May 17, 2012. Order 1000-A makes no substantive changes and did not specifically address Bonneville's issues regarding mandatory cost allocation. Certain parties have filed petitions for review of Orders 1000 and 1000-A with various United States Courts of Appeal.

Bonneville is preparing an Order 1000 compliance filing with ColumbiaGrid parties that would be consistent with Bonneville's statutory obligations regarding cost allocation. Bonneville would seek FERC approval of such filing, but the future of Bonneville's participation in regional planning with parties that include FERC-jurisdictional utilities will be uncertain if FERC does not approve such a compliance filing or if Order 1000's cost allocation is validated by a court.

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 power 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: (i) 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; (ii) are based on Bonneville's total system costs; and (iii) 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.

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 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—FERC and Non-discriminatory Transmission Access and the 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 under the Northwest Power Act is a final action subject to direct, exclusive review by the Ninth Circuit Court, if challenged. 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 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: (i) to Preference Customers and certain Federal agency customers; (ii) to DSIs; (iii) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program; and (iv) as requested, to meet the net requirements of investor-owned utilities. 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 two sites. Bonneville's environmental protection costs at one site are approximately $400,000 to date. Bonneville has not committed to any cleanup at this time pending a Record of Decision in 2012, but Bonneville's additional environmental protection costs at the site are not expected to exceed $100,000. Bonneville's potential liability for environmental protection costs at a second site is uncertain at this time, but is not expected to exceed $10 million.

Energy Policy Act of 2005

EPA-2005 was enacted by Congress in July 2005. Among other things, EPA-2005 amended the 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. On December 7, 2011, FERC, invoking this authority, rejected Bonneville's Interim Policies, on the basis it did not provide comparable transmission service, and ordered Bonneville to file tariff revisions addressing the comparability concerns raised in the proceeding. Bonneville filed amended tariff language on March 6, 2012, in response to FERC's ruling. See "—Wind Generation Development and Integration into the Federal Transmission System." FERC has not otherwise exercised its authority under this provision.

(ii) With respect to Bonneville's participation in an RTO, 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 an RTO, 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/Planning 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 mandatory reliability standards apply to Bonneville, but EPA-2005 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. Monetary penalties for violation of the standards may be assessed by the ERO and approved by FERC, but it has not yet been determined whether Congress authorized monetary penalties to be imposed on federal agencies, such as Bonneville.

2010 Dodd-Frank Act and Bonneville

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") provides for the reform of the financial industry in the United States. Under this legislation, regulation of over-the-counter ("OTC") swaps, futures, options, and derivatives will be substantially increased. The scope of the Dodd-Frank Act is very broad, and grants extensive discretion to applicable regulatory bodies, primarily the Commodities Futures Trading Commission ("CFTC") and the Securities and Exchange Commission ("SEC"). Congress directed the CFTC and SEC to establish and enforce rules and requirements for participants in a wide range of commercial and financial markets and they are establishing new rules on trading limits, and capital, reserve, and collateral requirements (primarily margin requirements).

Bonneville participates extensively in OTC future physical electric power transactions which call for physical delivery of electric power to market energy and to purchase energy to meet needs, and also to hedge market sales and purchases. The Dodd-Frank Act specifically excludes future physical delivery contracts from direct regulation. But as Dodd-Frank rulemaking efforts continue, new rules may adversely affect OTC physical energy markets and energy market participants. One result could be a significant drop-off in counterparty participation in the OTC future physical electric power market, thus decreasing market liquidity. As a result, Bonneville may look to exchange-traded, power-related financial swaps to manage risk in its market purchases and sales of electricity. Bonneville does not currently hold any exchange-traded, power-related financial swaps or other swap agreements such as interest rate swaps. It has entered into such transactions in the past though and may enter into them or similar agreements in the future. For further discussion about Bonneville's transaction risk management policies, see "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

As the regulatory agencies work to implement the Dodd-Frank Act, Bonneville cannot predict the impact to Bonneville of the new proposed or final rules. Depending on the final terms of the implementing rules, Bonneville's trading and financial operations could be affected directly or indirectly. Bonneville continues to actively monitor the rule-making process and related market changes in an effort to organize its trading activity so as to minimize any adverse financial impact on Bonneville's operations.

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.

Although the Treaty does not expire by its own terms, either the United States or Canada may elect to terminate it by providing not less than ten years' notice, with the earliest time for termination occurring in calendar year 2024. The United States Entity and Canadian Entity are each performing studies to assist their respective governments in determining whether to continue, amend, or terminate the Treaty post-calendar year 2024. The United States Entity expects to make a recommendation to the United States during calendar year 2014. Bonneville has not received any indication from either the United States or Canada of any interest in terminating the Treaty.

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.

In the past, the United States has narrowly avoided reaching its debt ceiling limitation. A future failure to raise the United States' debt ceiling could result in default by the United States and have adverse implications on all funds held by the United States Treasury, including the Bonneville Fund. Bonneville is unable to predict whether the United States Congress will fail to raise the United States' debt ceiling in the future. It is possible that actions taken or not taken by the United States Treasury or others at such times could materially affect Bonneville's operations and financial conditions, including, but not limited to, restrictions on Bonneville's ability to borrow either short- or long-term from the United States Treasury and on Bonneville's access to the Bonneville Fund including obtaining funds necessary to meet its payment obligations.

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.

Climate Change

Federal, regional, state, and international initiatives have been proposed or adopted to address global climate change by controlling or monitoring greenhouse gas emissions, by encouraging renewable energy development, and by implementing other measures. Bonneville cannot predict whether or when new laws and regulations or proposed initiatives would take effect in a manner that would affect Bonneville, and, if so, how they would affect Bonneville.

One of the major climate change policy initiatives that has been discussed at the national and regional levels is the pricing of carbon either through a cap and trade or a carbon tax. Federal legislation that would establish a national carbon price has become less likely in the near term. However, the State of California is scheduled to initiate a cap and trade platform in 2013 that would establish a carbon price in California. Other Western states or Canadian provinces could join the cap and trade platform through the Western Climate Initiative. The pricing of carbon is intended to disfavor the use of high carbon intensity resources, particularly coal. However, none of the generating facilities of the Federal System are fueled by carbon-based fuels. The Federal System generating facilities are primarily hydroelectric resources, or, in the case of Columbia Generating Station, nuclear-fueled. Therefore, it is unlikely that a carbon price would directly affect the cost of the output of the Federal System. However, a carbon price may increase the market price of electricity.

Bonneville frequently enters into short-term agreements for the purchase of electric power to make "balancing purchases" in periods of the year when Federal System generating facilities are not expected to be able to match loads. Further, in the past Bonneville has entered into and in the future expects to enter into similar market purchases in order to address longer term firm power deficits. To the extent that the electric power that Bonneville purchases for these purposes is derived from carbon-based generation, Bonneville could face increased costs if and when carbon emission regulation takes effect. However, Bonneville believes that cost increases in purchases would likely be offset by an increase in the relative value of its non-carbon-based seasonal surplus (secondary) energy, which is derived primarily from hydroelectric generating resources. In any event, given the predominance of non-carbon-based generation in the Federal System, to the extent that global warming initiatives impose controls or costs on carbon generation, Bonneville believes that the aggregate relative economic value of Bonneville's electric power probably would not decline, all else being equal.

To the extent that new regulations and incentives for non-carbon based generation increase the development of new generation facilities, Bonneville could face increased costs for integrating such facilities into the Federal Transmission System. However, Bonneville would be required by law to recover the costs in transmission and related rates. See "—Wind Generation Development and Integration into the Federal Transmission System." There may also be pressure to retire certain high carbon intensity resources early, particularly coal-fired generation. Given the resource profile of the Federal System, it is unlikely that the resources that produce power marketed by Bonneville will be closed early as a result of climate change policy.

The physical effects of climate change could affect the generation capability of the Federal System to meet loads. Given the Federal System's reliance on precipitation and snow pack, climate change could affect the amount, timing, and availability of hydroelectric generation. In addition, climate change could affect load patterns if space-heating and -cooling demands change, and if heat waves become more frequent and severe. Finally, changes in climate could adversely affect fish and wildlife populations affected by the Federal System, possibly resulting in additional costs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Wind Generation Development and Integration into the Federal Transmission System

Wind Generation Development and Integration

As the owner/operator of the Federal Transmission System, the largest bulk transmission system in the Region, Bonneville is responsible for transmitting electric power from and integrating most of the new wind generation projects that are located in the Region or that are transmitted into or through the Region. Bonneville estimates that 4,711 megawatts of wind generation facilities are now interconnected to the Federal Transmission System. Bonneville expects that an additional 320 megawatts of wind power will be integrated by the end of September 2014. Though the rate of growth of wind in the Region has slowed, wind generation integration beyond September 2014 is expected to continue to increase with future wind project development in the Region. With the enactment by Western states of renewable energy portfolio requirements applicable to electric power utilities, Bonneville expects that additional wind generation investments will continue to be made for the foreseeable future but at a lower level than previously anticipated.

The preceding megawatt estimates of wind generation reflect installed capacity of the facilities themselves and do not reflect estimated energy output, which depends on the availability and intensity of wind. Average generation over a year for all wind generation in the Region is roughly 30 percent of the installed capacity of the wind generation facilities.

From an electric power system perspective, Bonneville believes that wind energy provides no electric power capacity because its availability depends on the wind, and therefore is not reliable to be called on when needed. In addition, even when wind resources are generating, actual output can vary substantially in relatively short time frames. This means that other generating resources must be available and be relied on to provide necessary reserves to meet sudden declines in wind generation. Generation resources must also be available to be scaled back to accommodate unexpected upsurges in wind generation. Thus, integration of wind energy into the Federal Transmission System provides some operational challenges to assure system-wide reliability and the efficient effective transmission of wind from generation source to loads.

One of the complexities relates to the operation of the hydropower generating resources of the Federal System. While the Federal System hydropower is highly flexible since it can be called on to increase or decrease electric generation on short notice to manage wind fluctuations, system operation limitations restrict that flexibility. For example, in the spring and summer, the Federal System is operated to spill water to aid downstream migrant fish. Bonneville has developed processes to assure that wind generation integration does not adversely affect meeting ESA fish requirements by establishing the ability to cut wind generation schedules. Finally, integrating new resources (wind or otherwise) may also require facilities investments, such as new transmission lines and substations or improvements to existing facilities, in order to transmit the additional electric power. See "—Over-generation from High Water and High Wind."

All costs of Bonneville's wind integration efforts are recovered in its rates. See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

Since 2009, Bonneville's technical cross agency team has been developing and implementing initiatives designed to cost-effectively integrate large amounts of wind into the Federal System. These initiatives are designed to make better use of the existing system through improved wind forecasting and more flexible scheduling arrangements, to use dynamic scheduling to transfer some of the wind variability off of the Bonneville system, and to bring new resources into the marketplace for balancing services. Over time, these initiatives are intended to reduce dependence on the Federal System for balancing services and dampen the increase in wind integration costs.

Over-generation from High Water and High Wind

Apart from wind integration issues, continued wind power development may, from time to time, create reliability and environmental responsibility issues. Bonneville's seasonal surplus power is derived in the spring when river flows are the greatest. Coincidentally, the spring months also tend to be windy, and wind generation in the spring is often at its peak. The transmission system can only transmit an amount of power generation equal to loads, otherwise the system will destabilize. Thus, transmission balancing authorities such as Bonneville must reduce (displace) generation within its system so that power produced does not exceed demand.

In periods of high hydroelectric output, Bonneville can avoid forced displacement by agreeing with owners of thermal (coal, oil, and gas) generation to "economically displace" their thermal generation with low cost or free hydropower, thereby saving thermal fuel costs. Displacement of wind generation by Bonneville is more difficult given that wind generators do not have fuel costs, so the owners of the wind generation see no cost savings to be achieved by displacing their generation. Some wind generators also receive tax incentives in the form of state renewable energy credits or Federal production tax credits. These credits are based upon the amount of electric power actually generated, thus making economic displacement arrangements with wind generators more difficult to develop.

In June 2010, Bonneville experienced significant surplus hydropower combined with high levels of wind generation while energy demands were at relatively low levels. Further, certain Federal System hydroelectric facilities were operating pursuant to Clean Water Act requirements and court orders that limit spill in order to keep the amount of total dissolved nitrogen gas in the water below specific thresholds. High levels of total dissolved gases are harmful to ESA-listed fish species. Running water through the dam generators rather than spilling the water through the dam spillways is a critically important means to limit the amount of dissolved nitrogen. The need to generate power to avoid spill further increased Bonneville's interest in finding purchasers of its excess power. Absent increased demand needs, economic displacement is Bonneville's primary choice to offload its surplus generation. Bonneville looked principally to Regional thermal generators since wind generators generally have little economic incentive to displace their generation. Given the large amount of surplus hydropower available, Bonneville was offering its surplus generation at prices down to $0 per megawatt in place of the non-Federal thermal generation. The increase in wind generators combined with high wind conditions meant a larger portion of the Region's generation was coming from wind generators as opposed to thermal, thus making economic displacement a less effective tool. Despite the challenges, Bonneville successfully managed over-generation in June 2010.

With the growing wind fleet of 4,711 megawatts combined with the forecasted interconnection of 320 additional megawatts of wind generation capacity to the Federal System by September 2014, over-generation events have become more likely and more difficult to manage without resorting to displacement. After extensive public collaboration with stakeholders, Bonneville issued its Interim Policies on May 13, 2011. Under the Interim Policies, when required and only as a last resort to avoid harmful total dissolved gas levels, Bonneville displaced (or substituted) non-Federal generation with Federal power in its balancing authority area at no cost to the displaced non-Federal generators. When there were no off-takers of Federal electric power at the price of zero, Bonneville's Interim Policies thus required non-Federal generators (wind resources primarily) to curtail generation in an oversupply event. The Interim Policies did not provide for Bonneville to compensate entities, apart from the provision of free Federal hydro-generation, either to curtail their own generation or to take Federal power.

On June 13, 2011, several wind generators and transmission customers filed a complaint with FERC alleging that Bonneville's Interim Policies did not provide transmission service on terms and conditions that were comparable to those under which Bonneville provides transmission services to itself and requested, among other things, that FERC order Bonneville to cease implementation of its Interim Policies and that it file an open-access transmission tariff with FERC to remedy Bonneville's allegedly discriminatory practices. Bonneville filed its response on July 19, 2011. Bonneville also continued its public engagement and in June 2011 began settlement discussions with complainants and regional stakeholders. In addition, several parties filed petitions with the Ninth Circuit Court in July 2011, seeking review of Bonneville's Interim Policies. The Ninth Circuit Court cases are stayed until October 3, 2012, or pending final action by FERC on any request for rehearing or clarification in the related matter, whichever occurs first.

In an order issued December 7, 2011, FERC determined that Bonneville's Interim Policies did not provide for comparable transmission service. FERC ordered Bonneville to file tariff revisions addressing the comparability concerns raised in the proceeding. In response, on February 7, 2012, Bonneville released a proposed Oversupply Management Protocol for public comment and filed its proposed tariff revisions with FERC on March 6, 2012. Comments regarding Bonneville's tariff revisions in connection with the Oversupply Management Protocol were filed with FERC by March 27, 2012. While Bonneville and other parties await FERC's decision in this matter, Bonneville will apply its Oversupply Management Protocol, when required. In the spring of 2012, several parties filed petitions with the Ninth Circuit Court seeking review of Bonneville's Oversupply Management Protocol. The Ninth Circuit Court petitions are stayed pending final action by FERC. Additionally, certain wind generators and transmission customers may continue in their attempts to seek regulatory or legal redress for the Interim Policies and/or to challenge the Oversupply Management Protocol in other forums.

Under the Oversupply Management Protocol, Bonneville displaces generation from projects in its balancing authority area and compensates non-Federal generators that incur eligible costs from the displacement under a least cost displacement cost curve ("Cost Curve"). Under the Cost Curve, Bonneville begins displacing generators that do not incur costs as a result of displacement, and then following the Cost Curve, displaces from the least expensive to the most expensive generating resource, until the necessary relief is achieved. All displaced generators will receive Federal hydropower to meet their schedules. Eligible costs that a non-Federal generator may claim include the value of lost production tax credits and renewable energy credits, as well as lost contract revenues and penalties, arising from the failure to generate renewable energy, but only with respect to power sales agreements executed on or before March 6, 2012.

Starting in April 2012, Bonneville applied its Oversupply Management Protocol to displace non-Federal generation. Through August 15, 2012, Bonneville has displaced 49,654 megawatt hours of generation resulting in eligible displacement costs of approximately $3.2 million. Bonneville has compensated non-Federal generators for about $1 million of the eligible displacement costs to date and expects to provide credits for the additional $2.2 million of eligible displacement costs on future transmission bills of the non-Federal generators in the month following the displacement. Continued runoff and changing weather conditions present the possibility of oversupply events through September 2012. Bonneville estimates that on an expected value basis, it will compensate non-Federal generators about $12 million per year in aggregate, on average, to reduce electricity generation if oversupply events continue to occur. Under extreme conditions, compensation could exceed $50 million in a given year. Fiscal Year 2012 displacement compensation costs resulting from implementation of the Oversupply Management Protocol will be temporarily covered by Transmission Services' reserves until Bonneville establishes new rates to recover such costs and reimburse Transmission Services' reserves. Bonneville is considering allocating the displacement compensation costs equally between the Federal System users (primarily Preference Customers) and the compensated non-Federal generators within Bonneville's balancing authority area. Bonneville's proposal does not address any claims for damages associated with Bonneville's implementation of its Interim Policies.

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 Region, construction of major transmission facilities within the Region, 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, 2011, Bonneville had repaid $10.4 billion of principal of the Federal System investment and has $4.3 billion principal amount outstanding with regard to such appropriated investments and $2.9 billion principal outstanding in bonds issued by Bonneville to the United States Treasury.

Bonneville's repayment obligations include the payment of "irrigation assistance," which relates to appropriations provided to Reclamation to construct irrigation facilities associated with its Federal System projects. Bonneville's irrigation assistance obligation is limited to an amount of appropriations that is deemed under Reclamation policy to be beyond the ability of irrigators to pay. Examples of appropriated irrigation investments include water pumps, reservoir facilities and canals within the authorizations for the Federal System projects owned by Reclamation. These repayment obligations do not incur interest and therefore, in keeping with the principle (as embodied in DOE Order RA 6120.2) of scheduling repayments on the basis of highest interest repayment obligations first, are typically scheduled for recovery in Bonneville power rates in the year in which the expected life of the related facility (as determined near the time of construction) is reached. Bonneville expects that these payments will range between $1 million and $61 million per year over the next ten years.

Bonneville Borrowing Authority

Bonneville is authorized to issue and sell to the United States 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, $2.9 billion of bonds were outstanding as of September 30, 2011. 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 annual 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, 2011, the interest rates on the outstanding bonds ranged from 1.4 percent to 6.4 percent with a weighted average interest rate of approximately 4.2 percent. The original terms of the outstanding bonds vary from 4 to 30 years. The term of the bonds is limited by the average expected service life of the associated investment: 35 years for transmission facilities, 45 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.

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, as amended in Fiscal Year 2009, Bonneville may borrow and have outstanding at any one time up to $750 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 United States Treasury. Bonneville expects that the fund balance interest earnings under the investment model will be lower than if Bonneville were to have continued to earn interest credits on all of its balances under the prior practice.

Bonneville's Capital Program

Bonneville operates in a capital intensive industry. To meet a variety of needs, Bonneville is forecasting increased aggregate planned capital expenditures higher than levels in the recent past. Bonneville expects to fund substantial investment: (i) in the Federal Transmission System to assure reliable operation of existing facilities and to address new demands (such as integrating wind generation), (ii) in the hydroelectric dams of the Federal System to maintain and improve reliability and performance, and to protect fish and wildlife, (iii) in the conservation program established by the Council in its Sixth Power Plan, and (iv) to meet fish and wildlife capital commitments under the Columbia Basin Fish Accords with states and tribes in the Region, the 2010 Supplemental Columbia River System Biological Opinion, and the Willamette River Project Biological Opinion. Bonneville's capital expenditures also include certain heavy equipment and certain costs related to financing.

Bonneville's actual aggregate capital expenditures in Fiscal Years 2009, 2010, and 2011 were about $409 million, $604 million, and $799 million, respectively. Bonneville forecasts that its aggregate capital expenditures will be about $1,041 million in Fiscal Year 2012 and average about $1,108 million per year in the following five fiscal years. The foregoing capital spending amounts do not include capital expenditures for the Columbia Generating Station, the costs of which are also funded by Bonneville pursuant to the Net Billing Agreements as described in the Official Statement under the heading "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION—Capital Improvements," the cost of Columbia River fish mitigation funded by appropriations to the Corps, which are also repaid by Bonneville as part of Bonneville's Federal System appropriations repayment responsibility, and customer-funded projects for transmission integration and energy efficiency initiatives.

Transmission capital expenditures in Fiscal Years 2009, 2010, and 2011 were about $193 million, $305 million, and $301 million, respectively. Bonneville forecasts that annual transmission capital expenditures will average about $604 million per year in Fiscal Years 2012-2017. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

Conservation expenditures in Fiscal Years 2009, 2010, and 2011 were about $18 million, $58 million, and $162 million, respectively. Bonneville forecasts that annual conservation expenditures will average about $131 million per year in Fiscal Years 2012-2017. 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—Bonneville's Resource Program and Bonneville's Resource Strategies—Electric Power Conservation."

Federal System hydroelectric capital expenditures in Fiscal Years 2009, 2010, and 2011 were about $140 million, $148 million, and $201 million, respectively Bonneville forecasts that annual Federal System hydroelectric capital expenditures will average about $275 million in Fiscal Years 2012-2017.

There is substantial uncertainty in forecasting capital program needs.

Bonneville's Congressionally-enacted authority to borrow from the United States Treasury is not adequate to fund the entire projected capital program described above. While Bonneville expects that future capital expenditures in the next five to seven years will be financed primarily through remaining United States Treasury borrowing authority, Bonneville expects to employ third-party debt financing arrangements such as lease-purchases of transmission facilities to assist in obtaining financing for the capital program. Based on current and forecasted capital spending levels, Bonneville expects that it could reach the ceiling amount of its authority to borrow from the United States Treasury as early as 2016. Bonneville is working with its customers to develop a strategic approach to capital spending and funding sources to determine how Bonneville can best meet its capital program needs.

To the extent that Bonneville uses non-Treasury financing sources, the related debt service costs will be payable on the same parity as Net Billed Project costs, including debt service on Net Billed Bonds, in the order in which Bonneville's costs are met. See "—Order in Which Bonneville's Costs Are Met."

Order in Which Bonneville's Costs Are Met

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 2011 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $830 million in Fiscal Year 2011, approximately $70 million was for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. 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. Bonneville plans to make similar advance amortization payments to the United States Treasury at least through Fiscal Year 2012.

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 2012-D/E Bonds, 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. 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 2012-D/E Bonds, cash payments, if any, under the 1989 Letter Agreement, cash payments, if any, under the Direct Pay Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. 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's operating revenues include amounts equal to net billing credits if and as 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 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, although Bonneville is exploring the use of billing credits related to prepayments by Participants of future power bills. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Consideration of a Prepaid Power Program." For a description of the Net Billing Agreements, net billing, and Participants, 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 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 associated with repayment of appropriated Federal System investment in the Federal System, the deferred amount may be 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.

While all amounts in the Bonneville Fund are available to pay Bonneville's costs without regard to whether such costs are Power Services costs or Transmission Services costs, some reserves are derived from Power Services rates and operations and some are derived from Transmission Services rates and operations. (As of the end of Fiscal Year 2011, about $342 million in reserves were derived from Power Services rates and operations and $664 million were derived from Transmission Services rates and operations.) Because power rates are to be established to recover the costs of power operations and transmission rates are to be established to recover the cost of transmission operations, if Bonneville were to use Transmission Services-derived reserves to pay Power Services' costs, use of the Transmission Services' reserves would be treated as an obligation of Power Services, with the requirement that Power Services replenish any amounts of Transmission Services' reserves used.

Direct Pay Agreements

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. Under these agreements, 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.

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 are 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 the costs of the Net Billed Projects 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 balance, typically after Bonneville makes its end-of-fiscal-year payment 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. As a consequence of re-shaping its annual cash flow patterns under the Direct Pay Agreements, Bonneville has been able to adopt lower power rate levels than would have been expected in the absence of the Direct Pay Agreements. Bonneville believes that these beneficial power rate effects will persist so long as the Direct Pay Agreements remain in effect and are complied with.

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 the Official Statement under "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.

In December 2010, Bonneville and the Eugene Water & Electric Board ("EWEB") entered into a direct pay agreement. Under this agreement, Bonneville has agreed by contract to pay directly to EWEB its 30 percent share of the costs of the Trojan Nuclear Project as billed to Bonneville by EWEB. 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. The EWEB direct pay agreement did not and does not result in the amendment or termination of the EWEB Net Billing Agreement. There is no debt outstanding related to the Trojan Nuclear Project and EWEB's 30 percent share of the costs of the Trojan Nuclear Project is approximately $1.5 million per year.

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 2011 were $170 million, $88 million, and $22 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 $692 million to $827 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 and the Department of Interior prior to the expiration dates of the respective agreements.

As part of Bonneville's increased commitments for capital facilities to assist in Federal System fish and wildlife activities, in particular under the Columbia Basin Fish Accords, Bonneville has agreed in principle to establish a mechanism to use direct funding to finance certain capital expenditures of the Corps at its Federal System hydroelectric dams. Under this arrangement, Bonneville will borrow funds from the United States Treasury and transfer the funds to the Corps to make the expenditures. The debt service on the amounts borrowed from Treasury would be payable by Bonneville from "net proceeds." See "—Order in Which Bonneville's Costs Are Met."

Position Management and Derivative Instrument Activities and Policies

Bonneville seeks to ensure that its management of various financial risks is 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 composed 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.

Bonneville engaged in and concluded a pilot hedging program in 2011 involving exchange-traded, power-related financial swaps that do not require physical delivery. Due to changing market conditions in the OTC physical energy markets, Bonneville is exploring resuming using non-physical (financial) transactions in its hedging program. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—2010 Dodd-Frank Act and Bonneville." Such transactions will require Bonneville to provide collateral through the posting of margin payments to cover the credit risk absorbed by the exchange. Margin payments can affect Bonneville's cash flows, especially if large margin payments are required. For exchange-traded swaps, failure to meet margin calls can subject a party's related agreements to immediate termination and the net mark-to-market value of the related agreements may become immediately due and payable. In contrast, Bonneville does not currently provide collateral to secure any of its related physical power trading contract obligations, including OTC future physical electric power transactions.

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2009 through 2011 are set forth in the following "Federal System Statement of Revenues and Expenses (unaudited)" table. 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 and operation and maintenance costs of the Fish and Wildlife Service.

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

Fiscal Year ending September 30,	**2011**	**2010**	**2009**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities (1)	$ 1,762,498	$ 1,775,882	$ 1,673,237
Direct Service Industrial Customers	103,241	80,655	0
Northwest Investor-Owned Utilities	154,569	133,678	143,604
Sales outside the Northwest Region (2)	466,493	243,356	273,545
Book-outs (3)	(92,198)	(120,803)	(36,814)
Total Sales of Electric Power	2,394,603	2,112,768	2,053,572
Transmission (4)	775,770	770,504	713,907
Fish Credits and other revenues (5)	114,401	171,859	102,805
Total Operating Revenues	3,284,774	3,055,131	2,870,284
Operating Expenses:			
Bonneville O&M (6)	914,457	847,954	794,277
Purchased Power (3)	177,953	381,468	317,543
Corps, Reclamation, and Fish & Wildlife O&M (7)	280,349	271,502	255,059
Non-Federal entities O&M — net billed (8)	311,948	250,624	278,677
Non-Federal entities O&M — non-net billed (9)	42,788	38,638	45,236
Total Operation and Maintenance	1,727,495	1,790,186	1,690,792
Net billed debt service	608,171	546,987	461,888
Non-net billed debt service	16,801	53,373	39,479
Non-Federal Projects Debt Service (10)	624,972	600,360	501,367
Federal Projects Depreciation	393,502	368,371	355,574
Residential Exchange (11)	184,764	180,453	205,172
Total Operating Expenses	2,930,733	2,939,370	2,752,905
Net Operating Revenues	354,041	115,761	117,379
Interest Expense:			
Appropriated Funds	245,106	257,505	253,136
Long-term debt	135,141	83,608	60,908
Capitalization Adjustment (12)	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(42,983)	(32,866)	(30,710)
Net Interest Expense (13)	272,359	243,342	218,429
Net Revenues/(Expenses)	$ 81,682	$ (127,581)	$ (101,050)
Total Sales — average megawatts (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	11,042	8,936	8,748

(1) This customer group includes Preference Customers (municipalities, public utility districts, and rural electric cooperatives in the Region) and Federal agencies. This amount reflects refunds to Preference Customers arising from past overpayments of Residential Exchange Program benefits to Regional IOUs. Amounts applied in Fiscal Year 2011 were $85.1 million (see note 11 below).

(2) In general, revenues from sales outside the Region 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 associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for bookouts has no effect on net revenues, cash flows, or margins.

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

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife payment credits (also referred to as "4(h)10(C) credits") that reduce Bonneville's 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 $99.5 million, $123.1 million, and $85.1 million in Fiscal Years 2009, 2010, and 2011, 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 Accounting Standards Codification 815 ("ASC 815"), Derivatives and Hedging, Bonneville reported an unrealized mark-to-market loss of $34.7 million, an unrealized gain of $14.8 million, and no gain or loss in Fiscal Years 2009, 2010, and 2011, respectively. ASC 815 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 purchases and normal sales exception under ASC 815. Purchases and sales of forward electricity and option contracts that require physical delivery 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 ASC 815. These transactions are not required to be recorded at fair value in the financial statements. Bonneville does not apply hedge accounting. The gain or loss of zero in Fiscal Year 2011 compared to $14.8 million unrealized gain in Fiscal Year 2010, resulted from Bonneville applying Accounting Standards Codification 980, Regulated Operations, in Fiscal Year 2010 to its commodity contract derivative instruments that are recorded at fair value and do not meet the normal purchases and normal sales exception. As a result, unrealized gains or losses associated with Bonneville's derivative instruments are recorded on the Combined Balance Sheets under regulatory assets and regulatory liabilities rather than in the Combined Statements of Revenues and Expenses.

(6) Bonneville O&M expenses include the expenditures for the Federal Transmission System, Bonneville's operation and maintenance program, power marketing, and Bonneville's fish and wildlife programs.

(7) Corps, Reclamation, and Fish and Wildlife Service O&M 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 Energy Northwest's terminated Project 1, terminated Project 3, and operating Columbia Generating Station, and EWEB's 30 percent ownership share of the terminated Trojan Nuclear Project.

(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 Energy Northwest's nuclear power generating projects described in footnote (8) above.

(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." Bonneville's payments to Regional IOUs with respect to the Residential Exchange Program for the period July 1, 2001 through September 30, 2011, were originally established under Residential Exchange Program Settlement Agreements, as thereafter amended and supplemented. Bonneville suspended scheduled payments under the settlement agreements when they were invalidated by the Ninth Circuit Court in May 2007. In Fiscal Year 2008, Bonneville filed the 2009 Supplemental Power Rate Proposal with FERC to address the ruling. Under and in connection with that filing, Bonneville proposed to recover from Regional IOUs the overpayments (Refund Amounts) Bonneville made to them under the invalidated Residential Exchange Program Settlement Agreements. Bonneville also proposed to transfer these Refund Amounts to Preference Customers. Such Refund Amounts are being collected from identified Regional IOUs through credits to Residential Exchange Program benefits otherwise payable by Bonneville to the Regional IOUs and are being returned to the Preference Customers over time. The transferred amounts to Preference Customers do not reduce power rates for Preference Customers, but are reflected as credits to amounts that qualifying Preference Customers would otherwise pay to Bonneville for electric power and related services. (In some instances the transfers to Preference Customers will be effected by cash payments). Bonneville recognizes a refund and reduces expense in each year that Refund Amounts are recovered and transferred. These transactions with respect to the Refund Amounts are net operating revenue neutral as the same amount reduces both revenue and expense. The Refund Amount applied in Fiscal Year 2011 was $81 million. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

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

(13) 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.

Management Discussion of Operating Results

Fiscal Year 2011

For Fiscal Year 2011, net revenues were $82 million, a change of $210 million from negative net revenues of $128 million in Fiscal Year 2010.

For Fiscal Year 2011, Power Services and Transmission Services consolidated gross sales increased $255 million, or nine percent, from the prior fiscal year. Power Services gross sales increased $253 million, or eleven percent. The change was primarily due to several key factors. Firm sales increased $72 million, or four percent, in Fiscal Year 2011 compared to Fiscal Year 2010 due to higher PF power sales revenue resulting from increased power sales. In addition, for Fiscal Year 2011, Power Services had increased revenues from DSI sales since the DSI contracts were not in effect for the entire year in Fiscal Year 2010. Secondary sales increased $180 million, or 59 percent, in Fiscal Year 2011 compared to Fiscal Year 2010 due to much higher stream flows. A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in million acre feet or MAF) flowing through the Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2011 through July 2011 runoff volume at the Dalles Dam was 142 MAF, the fourth highest on record. For the entire Fiscal Year 2011, the Federal System experienced the sixth highest water year on record at 175 MAF, a significant increase from 110 MAF in Fiscal Year 2010 and above the historical average of 133 MAF.

Derivative instruments decreased to zero in Fiscal Year 2011 compared to $15 million unrealized gain at the end of Fiscal Year 2010, resulting from application of Regulated Operations accounting treatment beginning in Fiscal Year 2010 to the unrealized gains and losses related to certain power purchase and power sale contracts. As a result, these amounts are recorded on the Combined Balance Sheets under regulatory assets or regulatory liabilities rather than in the Combined Statements of Revenues and Expenses.

Operating expense decreased $9 million from Fiscal Year 2010. Operations and maintenance increased $145 million, or nine percent from the prior fiscal year, due in part to a $65 million increase for maintenance and biennial refueling for the Columbia Generating Station. See the Official Statement under "ENERGY NORTHWEST— THE COLUMBIA GENERATING STATION—Capital Improvements." Other key operating expense changes from the prior fiscal year were increases for Transmission Services operations and maintenance of $23 million, Fish and Wildlife Program of $22 million, and other agency expenses of $14 million. Fish and wildlife increases were driven by changes in the Council Program and in the ESA biological opinions. In addition certain transmission assets were impaired, resulting in a $21 million impairment charge. Gross purchased power expense decreased $204 million, or 53 percent, for Fiscal Year 2011 when compared to Fiscal Year 2010. This decrease was mainly the result of higher stream flows when compared to the prior fiscal year. Higher stream flows contributed to increased Federal System generation, which reduced the amount of power purchased to meet load. Non-Federal projects debt service increased $25 million, or four percent, primarily caused by an increase in scheduled debt repayments of $204 million for Project 1 and Project 3. The increase was offset by a reduction of $143 million for Columbia Generating Station. Another reduction was the non-recurrence in Fiscal Year 2011 of a one-time-only $34 million termination payment for two floating-to-fixed LIBOR interest rate swaps which occurred in Fiscal Year 2010.

Net interest expense for Fiscal Year 2011 increased $29 million, or 12 percent, compared to Fiscal Year 2010 primarily due to $15 million of call premiums paid for refinancing bonds issued to the United States Treasury and lower cash balances impacting interest earnings. Furthermore, in October 2010, $100 million was transferred from the Bonneville Fund to purchase United States Treasury securities as investments, which earned lower yields than was previously the case under prior practice. See "—Banking Relationship between the United States Treasury and Bonneville."

Fiscal Year 2010

For Fiscal Year 2010, net revenues were negative $128 million in Fiscal Year 2010, a change of $27 million from negative net revenues of $101 million in Fiscal Year 2009, primarily as a result of the factors discussed above. With respect to "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), modified net revenues were negative $164 million in Fiscal Year 2010 compared to $187 million modified negative net revenues in Fiscal Year 2009, representing an improvement of $23 million. Bonneville believes that under certain circumstances in effect during Fiscal Year 2010 and immediately preceding years, modified net revenues were a better reflection of Bonneville's financial results than standard accounting determinations of net revenues. However, modified net revenues may not be comparable to similarly titled measures of other companies and this measure is not intended to be a substitute for the net revenues from operations.

For Fiscal Year 2010, Power Services and Transmission Services consolidated gross sales increased $192 million, or seven percent, from the prior fiscal year. Power Services gross sales increased $143 million, or seven percent. The change was primarily due to several key factors. Regional requirements sales (to Preference Customers, DSIs, and Regional Federal agencies) increased $164 million in Fiscal Year 2010 compared to Fiscal Year 2009, due to higher power rates taking effect during Fiscal Year 2010. Secondary sales decreased $22 million in Fiscal Year 2010 compared to Fiscal Year 2009, due to lower than average stream flows and hydro-generation. In Operating Year 2010 this amount was 110 MAF. By contrast in Operating Year 2009 the amount was 117 MAF. In addition, the downturn in overall economic conditions resulted in lower demand and prices for seasonal surplus (secondary) energy and lower demand for firm power for Regional loads.

Transmission Services sales increased $49 million, or seven percent, based on increased transmission usage.

The change in the unrealized mark-to-market amount of Bonneville's derivative instruments to an unrealized gain of $15 million in Fiscal Year 2010 from an unrealized loss $35 million in Fiscal Year 2009 was primarily due to the termination of two floating-to-fixed interest rate swaps during the quarter ended March 31, 2010. This resulted in the realization of a $29 million loss, which is included in non-Federal projects expenses, and the corresponding removal of this position from this balance. Additionally, Bonneville's application of regulatory operations accounting treatment to its commodity contract derivative instruments in Fiscal Year 2010 resulted in a slight decrease in the unrealized losses recorded in the Statement of Revenues and Expenses.

Operating expense increased $186 million, or seven percent, from Fiscal Year 2009. Operations and maintenance increased $11 million from the prior fiscal year, due in part to a $24 million increase in Fish and Wildlife program expenses primarily driven by mitigation measures undertaken pursuant to the Columbia Basin Fish Accords. Other key operating expense changes from the prior fiscal year were an increase of $18 million for Federal hydroelectric projects system maintenance directly funded by Bonneville (meaning funded by Bonneville without appropriation to the Corps or Reclamation), a $6 million increase in Bonneville's Energy Efficiency Program, and a $5 million increase in Transmission Operations Program. These increases were partially offset by decreased expenses of $31 million for Columbia Generating Station associated with scheduled refueling and maintenance and a decrease in Residential Exchange Program payments of $25 million primarily due to a settlement in Fiscal Year 2009 with Avista (a Regional IOU). Gross purchased power expense increased $104 million, or 37 percent, for Fiscal Year 2010 when compared to Fiscal Year 2009. This increase was mainly due to purchasing power in the market to fulfill load obligations as a result of below normal basin-wide precipitation and stream flows, offset in part by a $40 million expense reduction due to the discontinuation of the monetization of DSI power sales. Operations to allow for fish mitigation measures also contributed to the need to purchase additional power. Non-Federal projects debt service increased $99 million, or 20 percent, primarily caused by an increase in scheduled debt repayments of $96 million for Energy Northwest's Project 1 and Columbia Generating Station. For two decades Energy Northwest's debt service was periodically restructured to achieve overall Federal and non-Federal debt service objectives. These restructurings reduced non-Federal projects expense. These debt management actions have created uneven Energy Northwest debt service such that there can be significant variances from year-to-year.

Net interest expense for Fiscal Year 2010 increased $25 million, or 11 percent, compared to Fiscal Year 2009 primarily due to a $22 million decrease in interest income as a result of lower cash balances and interest rates. Furthermore, in October 2009, $100 million was transferred from the Bonneville Fund to purchase United States Treasury securities as investments, which earned lower yields than was previously the case under prior practice. See "—Banking Relationship between the United States Treasury and Bonneville."

Fiscal Year 2009

For Fiscal Year 2009, net revenues were negative $101 million in Fiscal Year 2009. With respect to modified net revenues, modified net revenues were negative $187 million under conditions in effect in Fiscal Year 2009. Bonneville believes that modified net revenues were a better reflection of Bonneville's financial results than standard accounting determinations of net revenues.

For Fiscal Year 2009, Power Services and Transmission Services consolidated gross sales decreased $228 million, or eight percent, from the prior fiscal year. Power Services gross sales decreased $233 million, or 10 percent. The change was primarily due to several key factors. Revenues were down $490 million from Fiscal Year 2008 due to lower Federal System hydro-generation caused by less river runoff and reduced Columbia Generating Station output due to planned and unplanned outages. River runoff measured at The Dalles Dam was 117 MAF in Operating Year 2009 and 126 MAF in Operating Year 2008, compared to the historical average of 133 MAF. In addition, the downturn in the economy resulted in lower demand and prices for seasonal surplus (secondary) energy and lower demand for firm power for Regional loads.

To address the Ninth Circuit Court's ruling that set aside earlier Residential Exchange Program Settlement Agreements between Bonneville and each of the Regional IOUs, Bonneville supplemented its then-extant power rate proposal to begin correcting for the overpayments of Residential Exchange benefits and for the corresponding recovery of such costs in power rates charged to Preference Customers. Under this supplemental power rate proceeding and proposal, Bonneville's power rate levels for Fiscal Year 2009 were changed during the 2007-2009 Rate Period, resulting in PF Preference Rates other than for Slice customers being about one percent lower than for the same service in Fiscal Year 2008. The decrease in revenue from lower non-Slice PF Preference Rates was offset, however, by the effects of the Residential Exchange Program refunds by which Bonneville began recovering the past overpayments of Residential Exchange benefits to Regional IOUs. Refunds under this recovery program are obtained by Bonneville through payment offsets to Residential Exchange Program benefits paid to the Regional IOUs. These refunds were approximately $83 million in Fiscal Year 2009.

Transmission Services sales increased $5 million, or one percent, based on increased transmission usage.

The increase in the unrealized loss of Bonneville's derivative instruments of $4 million, or 13 percent, was due primarily to the following key factors: decrease in the 10 and 15 year forward Libor swap curves and decrease in the forward power price curve and its effect on Bonneville's commodity derivative instruments.

Operating expense increased $209 million, or eight percent, from Fiscal Year 2008. Operations and maintenance increased $322 million, or 26 percent, from the prior fiscal year, due primarily to: $206 million associated with correcting past overpayments of Residential Exchange Program benefits; $51 million increase in scheduled maintenance and biennial refueling; and $29 million increase in fish and wildlife expense. Gross purchased power expense decreased $172 million, or 38 percent, due to lower market prices and volume of purchases. The decrease was partially offset by a $40 million increase due to payments in lieu of power deliveries to the DSIs and an increase in purchased power due to the unplanned outage at Columbia Generating Station. Non-Federal Projects Debt Service increased $22 million, or five percent, due to increased Libor interest expense and repayment of Columbia Generating Station debt, partially offset by lower repayment of Energy Northwest's Project 1 and Project 3 debt.

Net interest expense decreased $10 million, or four percent, compared to Fiscal Year 2008. The primary reason for the decreased interest expense was a reduction of the weighted-average interest rates on outstanding appropriations owed and bonds issued to the United States Treasury.

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 are defined as total operating revenues less operating expenses. 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,	**2011**	**2010**	**2009**
Total Operating Revenues	$3,284,774	$3,055,131	$2,870,284
Less: Operating Expense(1)	1,640,415	1,707,561	1,640,904
Net Funds Available for Non-Federal Project Debt Service	1,644,359	1,347,570	1,229,380
Less:			
Non-Federal Project Debt Service(2)	624,972	600,360	501,367
Lease Financing Program(3)	23,872	20,718	17,369
Revenue Available for Treasury	995,515	726,492	710,644
Amount Allocated for Payment to Treasury(8):			
Corps and Reclamation O&M(4)	280,349	271,502	255,059
Net Interest Expense(5)	272,359	243,342	218,429
Lease Financing Program(3)	(23,872)	(20,718)	(17,369)
Capitalization Adjustment(6)	64,905	64,905	64,905
Allowance for Funds Used During Construction(5) (7)	25,022	16,109	12,093
Amortization of Principal	409,528	459,829	432,019
Total Amount Allocated for Payment to Treasury(8)	1,028,291	1,034,969	965,136
Revenues Available for Other Purposes(9)	(32,776)	(308,477)	(254,492)
Non-Federal Project Debt Service Coverage Ratio(10)	2.5	2.2	2.4
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio(11)	1.4	1.3	1.3

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(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 $39.5 million, $53.4 million, and $16.8 million for Fiscal Years 2009, 2010, and 2011 respectively.

(3) Includes related debt service amounts associated with lease payments by Bonneville with respect to certain transmission facilities owned by NIFC, NIFC II, NIFC III, NIFC IV, and NIFC V and 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 United States Treasury.

(4) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Reclamation, and Fish and Wildlife Service for Fiscal Years 2009, 2010, and 2011. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(5) 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 "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2009, 2010, and 2011 were $845 million, $864 million, and $830 million respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation, and Fish and Wildlife Service 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 Nine Months Ended June 30, 2012

For the nine months in the fiscal year-to-date ended June 30, 2012 ("Fiscal Year 2012 Third Quarter"), net revenues increased $4 million, or about two percent, when compared to the same period of the prior fiscal year. Power Services sales revenues decreased $21 million, or one percent, due to a decrease in both firm and secondary sales revenues. The $9 million, or one percent, decrease in revenue from firm sales was primarily the result of the new Tiered Rates that went into effect October 1, 2011. Tiered Rates significantly flatten the PF revenues across the year compared to the prior rate design, resulting in lower average rates in the nine months ended June 30, 2012. Secondary sales revenues decreased $18 million for the nine months ended June 30, 2012, compared to the same period in Fiscal Year 2011. Secondary sales revenues were down year-over-year due to an overall lower market price environment primarily driven by lower natural gas prices. The decline in price from the prior fiscal year outweighed the increase of available surplus in Fiscal Year 2012 compared to Fiscal Year 2011. Available surplus was lower in Fiscal Year 2011 due to extended outages at Columbia Generating Station and at the third powerhouse at Grand Coulee. Offsetting the reductions in firm and secondary sales was a $6 million reduction of the Residential Exchange Program refund amount. Transmission Services sales increased $38 million, or seven percent, mainly due to Point-to-Point long-term and Southern Intertie long-term sales, firm transmission services of one year or more delivering federal and non-federal power across the Federal Columbia River Transmission System; and ancillary service operating reserves, a reserve obligation needed to serve load in the event of a system contingency. Point-to-Point long-term sales increased by $17 million due to the energizing of the McNary - John Day transmission line, among other factors. Southern Intertie long-term sales increased by $7 million due to additional sales enabled by the California-Oregon Intertie improvement project. Operating reserve revenue was higher by $14 million largely due to an increase in the rates for operating reserves and a decrease in customer self-supplied operating reserves. For the nine months ended June 30, 2012, 4(h)(10)(C) credits decreased $10 million, or 15 percent, primarily due to lower forecasted direct capital program costs, lower prices of purchased power for fish mitigation, as well as lower volumes of power purchases compared to same period of the prior fiscal year.

Operations and maintenance expense increased $52 million, or four percent, for the nine months ended June 30, 2012, from the comparable period a year earlier due mainly to increases for Transmission Services operations and maintenance programs of $27 million, fish and wildlife of $35 million, Residential Exchange Program of $18 million, $13 million direct funding for Federal hydro projects, and other agency expenses of $6 million. Fish and wildlife increases were driven by the ongoing funding for the Council's Columbia River Basin Fish and Wildlife Program and the implementation ramp up of work in support of the 2010 Supplemental Columbia River System Biological Opinion and the Columbia River Basin Fish Accords. These increases were partially offset by decreases for operating generation costs at the Columbia Generating Station of $47 million as biennial maintenance and refueling were completed in Fiscal Year 2011.

Purchased power expense decreased $33 million, or 23 percent, for the nine months ended June 30, 2012, from the comparable period a year earlier. This decrease was due to a number of changes including lower market prices previously discussed, the Columbia Generating Station planned refueling and condenser replacement outage in Fiscal Year 2011 resulting in decreased generation for that year, and an improved generation outlook for Fiscal Year 2012 compared to Fiscal Year 2011. Largely offsetting this decrease was an increase of $31 million for Bonneville's current obligations under a hydro storage agreement. This agreement is through September 2024 and allows Bonneville to use additional storage space in Canada beyond the storage provided by the Columbia River Treaty.

Nonfederal projects expense increased $18 million, or four percent, for the nine months ended June 30, 2012, from the comparable period a year earlier primarily due to increased scheduled debt payments for Project 1 and Columbia Generating Station partially offset by reduced scheduled debt payments for Project 3.

Net interest expense decreased $23 million, or 12 percent, for the nine months ended June 30, 2012, from the comparable period a year ago. Interest expense decreased $4 million, or one percent, due to a reduction of costs allocated to power purposes at the Cougar Dam partially offset by increases associated with increased borrowings for continued expansion of transmission construction activity, conservation, and fish and wildlife. Allowance for funds used during construction increased $12 million, or 41 percent, reflecting increased construction work in progress balances related to capital investments for generation and transmission assets. Interest income increased $7 million, or 24 percent, as the result of a $16 million accrual for interest income related to outstanding receivables. This one time accrual was partially offset by the effect of lower cash balances and interest rates. Consistent with an agreement with the U.S. Treasury, annually increasing amounts of Bonneville's reserve balance have been and will be invested in U.S. Treasury market-based special securities in lieu of accruing interest rate credits based on the weighted average interest rate of Bonneville's outstanding bonds issued to the U.S. Treasury.

For further information regarding Fiscal Year 2012 Third Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED REPORT FOR THE NINE MONTHS ENDED JUNE 30, 2012." For information regarding Bonneville's Fiscal Year 2012 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2012 Expectations."

BONNEVILLE LITIGATION

In addition to the litigation described elsewhere in this Appendix A, Bonneville is also involved in the following matters:

ESA Litigation

Columbia River

In a lawsuit filed May 4, 2001, in the Oregon Federal District Court, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Federal Columbia River Power System 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 NOAA Fisheries to reinitiate consultation with the Action Agencies responsible for operation of the Federal System hydroelectric projects and to prepare a new biological opinion.

In early May 2003, the Oregon Federal District Court ruled 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 subsequent biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies identified by the Oregon Federal District Court. Plaintiffs filed a complaint against NOAA Fisheries and subsequently filed another complaint against the Corps and

Reclamation with the Oregon Federal 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 Administrative Procedures Act. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The court issued an order remanding the matter to the Federal agencies to correct identified deficiencies. Additionally, in the court's 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. The Federal Government and the State of Idaho appealed the order to the Ninth Circuit Court, which ultimately denied the appeals and upheld the order.

On May 5, 2008, NOAA Fisheries issued its 2008 Columbia River System Biological Opinion. On August 12, 2008, Bonneville issued its Record of Decision adopting the actions in the 2008 Columbia River System Biological Opinion. A number of parties filed litigation in the Oregon Federal District Court in connection with the 2008 Columbia River System Biological Opinion naming NOAA Fisheries, the Corps and Reclamation as defendants and alleging violations of the ESA as well as the Clean Water Act. In addition, some interests filed litigation in the Ninth Circuit Court against Bonneville regarding the 2008 Columbia River System Biological Opinion. The Ninth Circuit Court has exclusive direct review jurisdiction review over most of Bonneville's administrative actions.

Following oral and written statements by the Oregon Federal District Court judge, on September 15, 2009, the Federal agencies filed a "Management Plan" with the court. In the Management Plan, the Federal agencies outlined a more detailed and aggressive plan for implementing the adaptive management provisions of the 2008 Columbia River System Biological Opinion. On February 19, 2010, the Oregon Federal District Court judge entered a voluntary remand order that gave the Federal agencies three months to consider, among other things, integrating the Management Plan into the administrative record so that it may be taken into account in the court's evaluation of the 2008 Columbia River System Biological Opinion.

On May 20, 2010, NOAA Fisheries notified the court that it finalized the 2010 Supplemental Columbia River System Biological Opinion to supplement the existing 2008 Columbia River System Biological Opinion and incorporate the Management Plan. On June 11, 2010, the Federal agencies issued records of decision adopting the actions in the 2010 Supplemental Columbia River System Biological Opinion. Following briefing and a hearing, on August 2, 2011, the Oregon Federal District Court upheld the 2010 Supplemental Columbia River System Biological Opinion through 2013 since mitigation plans are adequate through that time period. Implementation costs are substantially similar to costs incurred in prior fiscal years. The court has ordered NOAA Fisheries to issue a new or supplemental Columbia River System Biological Opinion by January 1, 2014 for the period 2014 through 2018 and that such Biological Opinion identify specific mitigation measures and provide better scientific support for the conclusion that those measures will avoid jeopardy than was provided for such period in the 2010 Supplemental Columbia River System Biological Opinion. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "—The 2008 Columbia River System Biological Opinion, the 2010 Supplemental Columbia River System Biological Opinion and Related Developments."

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 Oregon Federal District 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 agencies 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 estimated 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 hydro-operations in each of 2007-2012, the Federal agencies proposed a spill program similar to the 2006 spill program and obtained court approvals. For 2013 river operations, the Federal agencies expect to propose spill programs for spring and summer as provided in the 2010 Supplemental Columbia River System Biological Opinion, which are similar to the 2006 spill program.

DSI Service 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 defined the service benefits that Bonneville would provide to the DSIs during Fiscal Years 2007 through 2011, among other things. The DSI ROD included the possibility that Bonneville would provide DSIs with service benefits in the form of either electric power at rates favorable to DSIs or monetized power benefits.

In September 2005, Alcoa, an aluminum industry DSI, and the Pacific Northwest Generating Cooperative ("PNGC"), a consortium of Bonneville Preference Customers, filed separate petitions for review in the Ninth Circuit Court challenging the DSI ROD. Alcoa asserted that Bonneville has a perpetual statutory obligation to serve DSIs with actual, physical power at Bonneville's lowest cost-based rates. Conversely, PNGC contended that Bonneville lacked statutory authority to provide any service benefits to DSIs.

In May 2006, Bonneville issued a Supplement to the DSI ROD that further defined the character of service that Bonneville would provide to DSIs in Fiscal Years 2007-2011 and in June 2006 Bonneville executed contracts (the "Original 2006 DSI Contracts") with Alcoa and CFAC, the two then-existing aluminum industry DSIs. (CFAC has since suspended operations but is considering resuming operations in August 2012.) In August 2006, Alcoa and PNGC filed additional petitions each of which challenged the Supplement to the DSI ROD and the Original 2006 DSI Contracts. As allowed under these contracts Bonneville elected to monetize the power it was obligated to sell and did so under the Firm Power Products and Services (FPS) rate schedule. (The FPS Rate Schedule provides Bonneville with substantial flexibility in pricing certain sales of power. Bonneville sells much of its seasonal surplus (secondary) energy at market prices under the FPS rate schedule, but sales under the FPS schedule are not limited to market price sales.) In October, 2006, Alcoa filed a petition challenging Bonneville's execution of a power sales contract to serve Port Townsend, a small non-aluminum industry DSI. Finally, in November 2006, the Industrial Customers of Northwest Utilities ("ICNU") filed a petition that likewise challenged the Port Townsend power sales contract.

In December 2008, the Ninth Circuit Court announced a decision (referred to as "PNGC I") affirming 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 industrial firm power to DSIs, Bonneville must first offer such power at the 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. The court also agreed with Bonneville that it has the authority to monetize its DSI contracts in some circumstances, so long as doing so is otherwise consistent with Bonneville's statutory obligations.

The Ninth Circuit Court also held that Bonneville impermissibly agreed in the Original 2006 DSI Contracts to monetize the difference between a rate for DSIs which was lower than the rate authorized by statute (the IP Rate) and lower than prices available on the open market. The foregone revenue resulted in higher rates for all other customers, making the contracts inconsistent with "sound business principles." The court remanded the case back to Bonneville to determine the applicability, in light of the court's holdings, of certain severability and damage waiver provisions in the contracts.

Thereafter, Bonneville and Alcoa agreed to contract amendments (the "Alcoa 2009 Amendment") to conform the Alcoa agreement to the PNGC I ruling. Bonneville believed that under the Alcoa 2009 Amendment, which was applicable to the last nine months of Fiscal Year 2009, the monetized power benefits it provided Alcoa in such period were likely be the same as expected under the original agreement. The Alcoa 2009 Amendment assured that in no event would the monetized power benefit be greater than expected under the original agreements. Bonneville and CFAC negotiated a substantially identical amendment (the "CFAC 2009 Amendment") for the last six months of Fiscal Year 2009, although the CFAC amendment also recalculated the amount of Bonneville's monetized benefits payments for two additional specified months.

In January 2009, PNGC and the Public Power Council ("PPC"), another coalition of Preference Customers, filed petitions ("PNGC II") in the Ninth Circuit Court challenging Bonneville's entry into the Alcoa 2009 Amendment. In August 2009, the court ruled that the Alcoa 2009 Amendment also was inconsistent with sound business principles. The court reiterated its remand to Bonneville to determine the applicability, in light of the court's holdings, of certain severability and damage waiver provisions in the contracts. To determine the applicability of the severability and damage waiver provisions, Bonneville issued a draft Record of Decision in August 2010 that contained analysis and conclusions with respect to its ability and likelihood of successfully recovering monies from the DSI customers. On February 18, 2011, Bonneville issued its final Record of Decision, which established that: (i) Bonneville is prohibited from seeking repayment from Alcoa and CFAC for the period October 1, 2006 through November 30, 2008 and that likewise the DSI customers are prohibited from pursuing claims of additional payments from Bonneville for that same period; (ii) although Bonneville is not contractually prohibited from seeking additional payments from Alcoa for the period of January 1, 2009 through September 30, 2009, it does not have a reasonable basis for doing so, and (iii) although Bonneville is not contractually prohibited from seeking additional payments from Port Townsend for the period of October 1, 2006 through September 30, 2009, it does not have a reasonable basis for doing so. In the spring of 2011, ICNU, certain Preference Customers, and Preference Customer associations filed separate suits in the Ninth Circuit Court challenging Bonneville's decision that it would not seek refunds from the DSIs. Briefing began in April 2012 and is scheduled to be complete by August 24, 2012.

On February 2, 2010, certain Preference Customers filed a motion to sever from certain power rates litigation (the Golden Northwest Proceeding described in "—Residential Exchange Program Litigation" below) an alleged ratemaking issue relating to DSI service. The Preference Customers filed a motion seeking an order from the Ninth Circuit Court directing Bonneville to calculate and refund amounts charged by Bonneville in rates paid by certain Preference Customers for power benefits that Bonneville provided to DSIs. On February 16, 2010, Bonneville, Alcoa, and Regional IOUs filed separate responses opposing the motion. The court denied the motion.

In November 2009, Bonneville entered into a 14-month power sales contract with Port Townsend for the sale of about 20 annual average megawatts through December 31, 2010. The parties have agreed to extend the term of this contract for the sale of about 20 annual average megawatts through August 31, 2013.

In December 2009, Bonneville entered into a long-term power sales contract with Alcoa (the "2009 Alcoa Contract"). Under the contract, Bonneville may sell up to 320 average megawatts of firm power each hour for a period of up to approximately seven years, at the IP Rate. The term of the contract was divided into two main periods, the Initial Period and the Second Period, with the Initial Period (including a one-year extension granted on October 29, 2010, a 35-day extension granted on May 23, 2012, a 30-day extension granted on July 1, 2012, and a 31-day extension granted on July 31, 2012) encompassing the approximately 32-month period from December 22, 2009, through August 31, 2012. The Second Period will not be offered. Instead, Bonneville and Alcoa have been discussing entering into a new power sales contract that would provide for the sale of 300 average megawatts to Alcoa for the ten-year period ending September 30, 2022.

In both DSI contracts, Bonneville has included terms that address the court's concerns as stated in PNGC II. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Power Sales—Power Sales to DSIs."

On January 22, 2010, Alcoa filed a petition for review in the Ninth Circuit Court challenging the 2009 Alcoa Contract and Bonneville's related record of decision, including Bonneville's associated interpretation of the PNGC I ruling. Three Regional IOUs, the Oregon Public Utilities Commission, PNGC, and PPC have intervened to challenge the Alcoa contract. Briefing is complete, oral argument was held on May 5, 2011, and the parties are awaiting a decision.

Tiered Rates Methodology Record of Decision

On January 27, 2009, ICNU filed a petition challenging Bonneville's Tiered Rates Methodology Record of Decision ("Tiered Rates ROD") and Bonneville's Tiered Rates Methodology, both issued November 10, 2008. Similar petitions for review were filed on February 5, 2009, by Georgia-Pacific, LLC ("GP") and Clatskanie People Utility District ("Clatskanie") challenging the same Tiered Rates ROD and the Tiered Rates Methodology.

All three petitioners challenged Bonneville's determination in the Tiered Rates ROD regarding Bonneville's treatment of "contracted for or committed to" loads, a term of art under section 3(13)(A) of the Northwest Power Act. These parties allege that Bonneville's decision to serve certain "contracted for or committed to" loads at Tier 2 PF Rates rather than at Tier 1 PF Rates violates provisions of the Northwest Power Act and is arbitrary and capricious under the Administrative Procedures Act. In addition, petitioner GP alleged that Bonneville's decision constituted a "taking" of its property under the Fifth Amendment of the U.S. Constitution for which "just compensation" is due. The court dismissed the petitions on July 16, 2010.

On September 15, 2010, Clatskanie filed a petition (similar to its earlier petition) challenging certain decisions contained in the Tiered Rates ROD and certain aspects of the Tiered Rates Methodology. Briefing is complete. Oral argument was held on July 11, 2012.

2010 and 2012 Power Rates Challenges

On July 21, 2009, Bonneville issued a Record of Decision at the conclusion of its 2010 Power and Transmission Rate Proposal (the "2010 Rates ROD"), which incorporated certain decisions from Bonneville's Fiscal Year 2002 and 2007 Supplemental Rate Cases. In October 2009, certain parties have filed petitions for review with the Ninth Circuit Court challenging certain decisions in the 2010 Rates ROD to the extent they involve non-ratemaking issues that might be subject to the court's jurisdiction prior to FERC's final approval of the 2010-2011 Rates. These petitions were stayed pending FERC's final approval of the 2010-2011 Rates.

FERC approved the 2010-2011 Rates in August 2010. In early November 2010, certain Regional IOUs, Preference Customers, and a group of industrial customers filed petitions to challenge the 2010-2011 Rates and the decisions Bonneville reached in the 2010 Rates ROD. It is unclear which aspects of the rates and/or ratemaking process are being challenged. These petitions were consolidated with the earlier petitions that challenged the 2010 Rates ROD. See "—Residential Exchange Program Litigation."

On July 26, 2011, Bonneville issued a Record of Decision at the conclusion of its 2012 Power and Transmission Rate Proposal (the "2012 Rates ROD"), which incorporated certain decisions from Bonneville's Fiscal Year 2002, Fiscal Year 2007 Supplemental, and Fiscal Year 2010 power rate proceedings. In October 2012, certain parties filed petitions for review with the Ninth Circuit Court challenging certain decisions in the 2012 Rates ROD to the extent they involve non-ratemaking issues that might be subject to the court's jurisdiction prior to FERC's final approval of the 2012-2013 Rates. These petitions have been consolidated and are stayed until the earlier of FERC's final approval of the 2012-2013 Rates or November 2012.

Residential Exchange Program Litigation

In Fiscal Year 2000, Bonneville and each of the six Regional IOUs entered into certain "2000 Residential Exchange Program Settlement Agreements" that proposed to define Bonneville's statutory obligations under the Residential Exchange Program provisions of the Northwest Power Act for the five- and ten-year periods beginning October 1, 2001. The 2000 Residential Exchange Program Settlement Agreements provided for fixed payments and power sales to Regional IOUs in lieu of reliance on rate-period-by-rate-period determinations of their Residential Exchange Program benefits. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." In 2004, Bonneville and certain Regional IOUs entered into amendments to their respective 2000 Residential Exchange Program Settlement Agreements, with the effect, among other things, of extending the term of all of the 2000 Residential Exchange Program Settlement Agreements to the end of Fiscal Year 2011.

Beginning in 2000, a number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the 2000 Residential Exchange Program Settlement Agreements, among other things. 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 2000 Residential Exchange Program Settlement Agreements is referred to as the "PGE Proceeding." Certain customers also challenged, in another proceeding referred to as the "Golden Northwest Proceeding," Bonneville's power rates in Fiscal Years 2002 through 2006 associated with the 2000 Residential Exchange Program Settlement.

On May 3, 2007, the Ninth Circuit Court issued an opinion in the PGE Proceeding holding that Bonneville failed to properly implement the Residential Exchange Program provisions of the Northwest Power Act when it entered into the 2000 Residential Exchange Program 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 2000 Residential Exchange Program Settlement Agreements. The Regional IOUs filed petitions for rehearing of the ruling in the PGE Proceeding. The motions were denied.

In response to the court's rulings regarding the 2000 Residential Exchange Program Settlement Agreements and related power rates, in 2008, Bonneville initiated a 2007 Supplemental Power Rate proceeding and separately initiated processes to establish new long-term and interim Residential Purchase and Sales Agreements ("RPSA") to implement the Residential Exchange Program and to revise the Average System Cost (ASC) Methodology that is a key element of the Residential Exchange Program. Bonneville and each of the five regional IOUs that expected to qualify for Residential Exchange Program benefits in Fiscal Year 2009 signed the new RPSAs. The 2007 Supplemental Power Rate Proposal proceeding concluded with a Record of Decision dated September 22, 2008. In its 2007 Supplemental Power Rate Record of Decision ("2007 Supplemental ROD"), Bonneville addressed the court's Residential Exchange Program rulings by determining the amounts overpaid to the Regional IOUs under the 2000 Residential Exchange Program Settlement Agreements ("Refund Amounts") and initiating the return of such overpaid amounts to Preference Customers, whose past PF Rates were higher than should have been the case.

Bonneville also established in the 2007 Supplemental ROD power rates and Residential Exchange Program benefits for Fiscal Year 2009. Bonneville customers and other parties filed legal challenges to the Refund Amount determinations, power rates, long-term and interim RPSAs, and related matters. FERC granted final approval of Bonneville's 2009 Power Rates on July 16, 2009, and granted final approval of the revised ASC Methodology in September 2009. Thereafter, certain parties filed petitions for review with the Ninth Circuit Court of Bonneville's decisions in the 2007 Supplemental ROD and of the related rates.

In July 2009, Bonneville concluded its rate case in which Bonneville established rates for 2010-2011 Rate Period. Among other decisions made in this rate proceeding, Bonneville continued the Residential Exchange Program as set forth in the 2007 Supplemental ROD. Subsequently parties filed petitions with the Ninth Circuit Court challenging, among other things, the 2010-2011 Rates' Residential Exchange Program.

In late 2010, most of the litigants in the aforementioned litigation developed a proposed settlement agreement of the outstanding Residential Exchange Program-related issues which became the 2012 Residential Exchange Program Settlement. Litigants and others representing most Regional parties including all six Regional IOU customers, 89 percent of Bonneville's aggregate Preference Customer load, three state utility commissions, and several Preference Customer trade groups submitted the 2012 Residential Exchange Program Settlement to Bonneville for review and execution. Bonneville conducted an evidentiary hearing to review the proposed settlement. On July 26, 2011, Bonneville issued a Record of Decision, agreeing to adopt the 2012 Residential Exchange Settlement Agreement.

On August 8, 2011, Bonneville and certain Preference Customers that signed the 2012 Residential Exchange Program Settlement filed a join motion to dismiss the Residential Exchange Program-related issues from the above pending appeals on the basis that the 2012 Residential Exchange Program Settlement rendered such appeals moot. Regional-IOUs filed a separate motion to stay related proceedings.

In October of 2011, Alcoa and the Association of Public Agency Customers filed petitions challenging the 2012 Residential Exchange Program Settlement and supporting Record of Decision, dated July 26, 2011. These petitions were consolidated. The Ninth Circuit Court stayed all litigation activity on the claims that form the basis of the existing Residential Exchange Program disputes pending a decision in this case. Petitioners filed opening briefs in February 2012 and Bonneville filed its answering brief on April 30, 2012. Briefing was completed July 19, 2012. Oral arguments are yet to be scheduled. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—2012 Residential Exchange Program Settlement" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

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. The two following claims have yet to be resolved completely.

> **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.
>
> **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.

Rates Litigation Generally

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 "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. 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.

Lease-Purchase Program Property Taxes

On May 6, 2010, the United States of America and Bonneville filed a complaint in Oregon Federal District Court challenging the assessment of real property tax by the Oregon Department of Revenue against transmission assets located in several Oregon counties and leased by Bonneville under capitalized lease-purchase agreements. Under the related leases, Bonneville contracted with the respective asset owners to pay the cost of any associated property tax liability. The Oregon Department of Revenue issued a formal declaratory ruling in January 2010 concluding that such assets are subject to real property taxation in Oregon. On January 4, 2011, the Oregon Federal District Court granted the defendants' motions to dismiss and dismissed the case without prejudice. On January 13, 2011, the Oregon Department of Revenue re-issued its declaratory ruling, as required by the Oregon Federal District Court order, to allow for timely appeal of the ruling to the Oregon Tax Court. Bonneville and the United States have appealed the Oregon Federal District Court decision to the Ninth Circuit Court. Briefing is complete. In April 2011, the United States filed new complaints in Oregon Federal District Court and Oregon Tax Court. On June 24, 2011, the Oregon Federal District Court dismissed the second Oregon Federal District Court case without prejudice.

The United States has also appealed the second Oregon Federal District Court decision to the Ninth Circuit Court. Both appeals to the Ninth Circuit Court have been consolidated. Briefing is complete. Oral argument for the consolidated appeals is scheduled to be held on October 12, 2012. The Oregon Department of Revenue agreed to toll assessment pending final resolution of this matter. Bonneville estimates that the total tax at issue for 2009-2012 is approximately $3,200,000. Depending on the outcome of the litigation and related events, Bonneville may have to pay the costs of these and future potential tax assessments for lease-purchased facilities in Oregon. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

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.

pwc

Report of Independent Auditors

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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2011, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the 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

October 27, 2011

PricewaterhouseCoopers LLP, 1300 SW Fifth Ave, Suite 3100, Portland, OR 97201
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Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Thousands of Dollars)

	2011	2010
Assets		
Utility plant		
Completed plant	**$ 14,741,720**	$ 14,362,387
Accumulated depreciation	**(5,436,160)**	(5,247,971)
	9,305,560	9,114,416
Construction work in progress	**1,396,097**	1,105,165
Net utility plant	**10,701,657**	10,219,581
Nonfederal generation	**2,604,078**	2,449,865
Current assets		
Cash and cash equivalents	**892,125**	1,078,671
Short-term investments in U.S. Treasury securities	**253,348**	65,783
Accounts receivable, net of allowance	**119,596**	122,400
Accrued unbilled revenues	**207,089**	197,603
Materials and supplies, at average cost	**93,924**	85,797
Prepaid expenses	**29,430**	25,832
Total current assets	**1,595,512**	1,576,086
Investments and other assets		
Regulatory assets	**7,812,358**	4,983,142
Investments in U.S. Treasury securities	**39,129**	82,328
Nonfederal nuclear decommissioning trusts	**198,809**	188,850
Deferred charges and other	**223,736**	169,318
Total investments and other assets	**8,274,032**	5,423,638
Total assets	**$ 23,175,279**	$ 19,669,170

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Thousands of Dollars)

	2011	2010
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,510,373**	$ 2,428,691
Federal appropriations	**4,324,881**	4,238,167
Borrowings from U.S. Treasury	**2,678,440**	2,188,440
Nonfederal debt	**5,843,046**	6,015,585
Total capitalization and long-term liabilities	**15,356,740**	14,870,883
Commitments and contingencies (Note 13)		
Current liabilities		
Federal appropriations	**24,622**	21,232
Borrowings from U.S. Treasury	**265,000**	325,000
Nonfederal debt	**429,545**	306,175
Accounts payable and other	**523,459**	613,052
Total current liabilities	**1,242,626**	1,265,459
Other liabilities		
Regulatory liabilities	**2,456,343**	2,494,019
IOU exchange benefits	**3,161,251**	85,017
Asset retirement obligations	**176,212**	170,334
Deferred credits and other	**782,107**	783,458
Total other liabilities	**6,575,913**	3,532,828
Total capitalization and liabilities	**$ 23,175,279**	$ 19,669,170

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Statements of Revenues and Expenses
For the Years Ended September 30

(Thousands of Dollars)

	2011	2010	2009
Operating revenues			
Sales	**$ 3,134,209**	$ 2,851,097	$ 2,742,770
Derivative instruments	**-**	14,800	(34,677)
U.S. Treasury credits for fish	**85,102**	123,090	99,499
Miscellaneous revenues	**65,463**	66,144	62,692
Total operating revenues	**3,284,774**	3,055,131	2,870,284
Operating expenses			
Operations and maintenance	**1,734,306**	1,589,171	1,578,421
Purchased power	**177,953**	381,468	317,543
Nonfederal projects	**624,972**	600,360	501,367
Depreciation and amortization	**393,502**	368,371	355,574
Total operating expenses	**2,930,733**	2,939,370	2,752,905
Net operating revenues	**354,041**	115,761	117,379
Interest expense and (income)			
Interest expense	**352,904**	331,255	326,494
Allowance for funds used during construction	**(42,983)**	(32,867)	(30,710)
Interest income	**(37,562)**	(55,046)	(77,355)
Net interest expense	**272,359**	243,342	218,429
Net revenues (expenses)	**81,682**	(127,581)	(101,050)
Accumulated net revenues at October 1	**2,428,691**	2,556,272	2,664,460
Irrigation assistance	**-**	-	(7,138)
Accumulated net revenues at September 30	**$ 2,510,373**	$ 2,428,691	$ 2,556,272

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System

Combined Statements of Changes in Capitalization and Long-Term Liabilities

Including Current Portions

(Thousands of Dollars)

Balance at September 30	Accumulated Net Revenues	Federal Appropriations	Borrowings from U.S. Treasury	Nonfederal Debt	Total
2009	$ 2,556,272	$ 4,396,189	$ 2,130,440	$ 6,564,934	$ 15,647,835
Federal appropriations:					
Proceeds	-	68,039	-	-	68,039
Repayment	-	(204,829)	-	-	(204,829)
Borrowings from U.S. Treasury:					
Proceeds	-	-	638,000	-	638,000
Repayment	-	-	(255,000)	-	(255,000)
Nonfederal debt:					
Proceeds	-	-	-	27,351	27,351
Repayment	-	-	-	(270,525)	(270,525)
Net expenses	(127,581)	-	-	-	(127,581)
2010	$ 2,428,691	$ 4,259,399	$ 2,513,440	$ 6,321,760	$ 15,523,290
Federal appropriations:					
Proceeds	**-**	**129,632**	**-**	**-**	**129,632**
Repayment	**-**	**(39,528)**	**-**	**-**	**(39,528)**
Borrowings from U.S. Treasury:					
Proceeds	**-**	**-**	**800,000**	**-**	**800,000**
Repayment	**-**	**-**	**(370,000)**	**-**	**(370,000)**
Nonfederal debt:					
Proceeds	**-**	**-**	**-**	**349,108**	**349,108**
Extinguished through refinancing	**-**	**-**	**-**	**(90,000)**	**(90,000)**
Repayment	**-**	**-**	**-**	**(308,277)**	**(308,277)**
Net revenues	**81,682**	**-**	**-**	**-**	**81,682**
2011	**$ 2,510,373**	**$ 4,349,503**	**$ 2,943,440**	**$ 6,272,591**	**$ 16,075,907**

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Statements of Cash Flows
For the Years Ended September 30
(Thousands of Dollars)

	2011	2010	2009
Cash provided by and (used for) operating activities			
Net revenues (expenses)	**$ 81,682**	$ (127,581)	$ (101,050)
Non-cash items:			
Depreciation and amortization	**393,502**	368,371	355,574
Amortization of nonfederal projects	**306,175**	270,525	189,882
Unrealized (gain) loss on derivative instruments	**-**	(14,800)	34,706
Changes in:			
Receivables and unbilled revenues	**(5,112)**	(30,109)	32,561
Materials and supplies	**(8,127)**	(8,185)	(1,893)
Prepaid expenses	**(3,598)**	(1,180)	(2,970)
Accounts payable and other	**(50,229)**	91,915	(138,548)
Regulatory assets and liabilities	**(209,173)**	(164,775)	35,897
Other assets and liabilities	**(68,134)**	(13,813)	(135,690)
Net cash provided by operating activities	**436,986**	370,368	268,469
Cash provided by and (used for) investing activities			
Investment in:			
Utility plant (including AFUDC)	**(787,384)**	(683,680)	(575,083)
U.S. Treasury Securities:			
Purchases	**(310,000)**	(100,000)	(110,000)
Maturities	**163,193**	44,683	9,891
Deposits to nonfederal nuclear decommissioning trusts	**(9,616)**	(8,753)	(8,211)
Special purpose corporations' trust funds:			
Deposits to	**(106,260)**	(4,646)	(199,916)
Receipts from	**66,601**	39,780	108,081
Net cash used for investing activities	**(983,466)**	(712,616)	(775,238)
Cash provided by and (used for) financing activities			
Federal appropriations:			
Proceeds	**129,632**	86,470	176,887
Repayment	**(39,528)**	(204,829)	(38,559)
Borrowings from U.S. Treasury:			
Proceeds	**800,000**	638,000	338,000
Repayment	**(370,000)**	(255,000)	(393,460)
Nonfederal debt:			
Proceeds	**201,963**	4,646	199,916
Extinguished through refinancing	**(90,000)**	-	-
Repayment	**(308,277)**	(270,525)	(189,882)
Customers:			
Advances for construction	**59,806**	92,786	63,492
Reimbursements to customers	**(23,662)**	(27,648)	(16,706)
Irrigation assistance paid	**-**	-	(7,138)
Net cash provided by financing activities	**359,934**	63,900	132,550
Net decrease in cash and cash equivalents	**(186,546)**	(278,348)	(374,219)
Cash and cash equivalents at beginning of year	**1,078,671**	1,357,019	1,731,238
Cash and cash equivalents at end of year	**$ 892,125**	$ 1,078,671	$ 1,357,019
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 375,755**	$ 360,813	$ 362,305
Significant noncash investing and financing activities:			
Accrued capital expenditures increase	**$ 43,586**	$ 46,247	$ 33,328
Federal appropriations write-off	**$ -**	$ (18,431)	$ -
Nonfederal debt increase for Energy Northwest	**$ 147,145**	$ 22,705	$ 88,028

The accompanying notes are an integral part of these statements.

Notes to Financial 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 Financing.)

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 intracompany and intercompany 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 directives issued by U.S. government agencies. BPA is a separate and distinct entity within 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 subject to an extensive formal hearing 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 ensure 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 are subject to review 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 accordance with authoritative guidance for Regulated Operations, certain costs or credits may be included in rates for recovery or refund over a future period and are recorded as regulatory assets or liabilities. (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. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return.

Utility plant

Utility plant is stated at original cost and includes generation and transmission assets. Generation assets were $7.96 billion and $7.76 billion, and transmission assets were $6.78 billion and $6.60 billion at Sept. 30, 2011, and 2010, respectively. The costs of substantial 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. When BPA retires utility plant, it charges the original cost and any net proceeds from the disposition to accumulated depreciation.

Depreciation

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated service lives of the various classes of property, which average 75 years. For transmission plant, depreciation of original cost and estimated net cost of removal is computed primarily on the straight-line group life method based on estimated service lives of the various classes of property, which average 40 years. The net cost of removal is included in depreciation; however, in the event there is negative salvage, a reclassification of the negative salvage reserve not associated with asset retirement obligations 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 non-cash 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 and the NIFCs. The rates for appropriated funds are provided each year to BPA by the U.S. Treasury, whereas the BPA rate is determined based on the weighted-average cost of borrowing for BPA and the NIFCs. The respective rates were approximately 0.3 percent and 4.4 percent in fiscal year 2011, 0.4 percent and 4.8 percent in fiscal year 2010, and 2.0 percent and 5.2 percent in fiscal year 2009.

Nonfederal generation

BPA has acquired all of the generating capability of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant. The contracts to acquire the generating capability of the project require BPA to cover all of CGS's operating, maintenance and debt service costs. BPA also has acquired all of the output of the Lewis County PUD's Cowlitz Falls Hydroelectric Project and pays all related operating, maintenance and debt service costs. BPA recognizes expenses for these projects based upon total project cash funding requirements. The nonfederal generation assets in the Combined Balance Sheets are amortized over the term of the outstanding debt. (See Note 8, Nonfederal Financing.)

Cash and cash equivalents

Cash amounts include cash in the BPA fund with the U.S. Treasury and unexpended appropriations of the Corps and Reclamation. Cash equivalents represent short-term U.S. Treasury market-based special securities with maturities of 90 days or less at the date of investment. (See Note 2, Investments in U.S. Treasury Securities.) The carrying value of cash and cash equivalents approximates fair value.

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 consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators 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 2011, 2010 and 2009, 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, parental guarantees, cash in the form of prepayment and deposit or escrow from some counterparties. BPA closely monitors counterparties for changes in financial condition and regularly updates credit reviews.

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 customer 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 not fully paid BPA for their purchases. (See Note 13, Commitments and Contingencies.) BPA has recorded an allowance for these accounts, which in management's best estimate is sufficient to cover potential exposure. Net exposure after this allowance is not significant. BPA has continued to pursue collection of amounts due.

Derivative instruments

BPA follows the Derivatives and Hedging accounting guidance that requires 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 purchases and normal sales exception under the Derivatives and Hedging accounting guidance. Forward electricity contracts are generally considered normal purchases and normal sales if they 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 the Derivatives and Hedging accounting guidance. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

In fiscal year 2010, BPA began applying Regulated Operations accounting treatment to its derivative instruments that do not qualify for the normal purchases and normal sales exception and are recorded at fair value. As such, unrealized gains or losses associated with these derivative instruments are recorded on the Combined Balance Sheets under Regulatory assets or Regulatory liabilities.

Fair value

BPA's carrying amounts of current assets and current liabilities approximates fair value based on the short-term nature of these instruments. In accordance with authoritative guidance for Fair Value Measurements and Disclosures, BPA uses fair value measurements to record adjustments to certain financial assets and liabilities and to determine fair value disclosures. When developing fair value measurements, it is BPA's policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry standard models that consider various inputs including: (a) quoted forward prices for commodities; (b) time value; (c) volatility factors; (d) current market and contractual prices for underlying instruments; (e) market interest rates and yield curves; and (f) credit spreads, as well as other relevant economic measures. (See Note 11, Risk Management and Derivative Instruments and Note 12, Fair Value Measurements.)

Revenues and net revenues

Operating revenues are recorded when services are rendered and include estimated unbilled revenues. BPA's net revenues over time are committed to repayment of the U.S. government investment in the FCRPS, the payment of certain irrigation costs and the payment of operational obligations, including debt for both operating and nonoperating nonfederal projects. (See Note 13, Commitments and Contingencies.)

Interest income

Interest income includes interest earned on BPA's fund balance with the U.S. Treasury and interest earned on investments in market-based special securities. BPA earns interest on cash balances in the fund at the weighted-average interest rate of its outstanding U.S. Treasury borrowings and reduces its monthly debt interest payments by the interest earned. Interest earnings on investments are based on the stated rates of the individual market-based special securities.

U.S. Treasury credits for fish

The Northwest Power Act 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. Power related costs are recovered in BPA's rates. Nonpower related costs are recovered as a reduction to BPA's cash payment to the U.S. Treasury.

Residential Exchange Program

In order to provide qualifying regional utilities, primarily IOUs, 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, BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA's priority firm exchange rate to the utility for resale to that utility's residential and small farm consumers. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing rates. The cost of this program is collected through rates with program costs recognized when incurred net of the purchase and sale of power under the REP.

In fiscal year 2008, BPA conducted the 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case) to resolve outstanding claims and address associated judicial rulings related to prior REP billings. In 2009, BPA conducted the 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (WP-10 Rate Case), continuing the policies established in WP-07 Supplemental Rate Case. In connection with those filings, Lookback Amounts due to and due from BPA customers were identified and recorded as regulatory amounts. Such Lookback Amounts were collected from identified IOU customers and were being returned to the COUs over time.

In fiscal year 2011, the BPA administrator signed the 2012 Residential Exchange Program Settlement Agreement (Settlement Agreement), resolving disputes related to the REP. The Settlement Agreement provides for fixed “Scheduled Amounts” payable to the IOUs, as well as fixed “Refund Amounts” payable to the COUs. The Settlement Agreement eliminates the Lookback Amounts as of Sept. 30, 2011, but replaces them with the Refund Amounts for amounts overpaid by the COUs. These amounts do not reduce rates, but are reflected as credits to qualifying COUs’ bills as designated in the Settlement Agreement. BPA utilizes the rates process to reduce the IOUs’ benefits and thus reduce expense in the year it is applied. These transactions are net operating revenue neutral as the same amount reduces both revenue and expense. (See Note 9, Residential Exchange Program.)

RECENT ACCOUNTING PRONOUNCEMENTS

Receivables

In July 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance requiring new disclosures about the credit quality of certain financing receivables, as well as the related allowances for credit losses. The required disclosures are intended to facilitate financial statement users' evaluation of the nature of credit risk inherent in an entity's portfolio of financing receivables, how that risk is assessed and analyzed in arriving at the allowance for credit losses and the reasons for those changes in the allowance for credit losses. The disclosures are required to be made on a disaggregated basis and include qualitative and quantitative information about financing receivables, the allowance for credit losses, impaired balances and credit quality indicators. This guidance will be effective for fiscal year 2012. BPA is determining the extent to which financing receivables guidance is, or will be, relevant to BPA and the potential related impact on BPA's financial statements.

Fair value measurements and disclosures

In January 2010, the FASB issued authoritative guidance related to fair value disclosures. The guidance requires additional detailed disclosure for all levels of fair value measurements. The amounts of significant transfers in and out of Levels 1 and 2 are required to be disclosed, along with the reasons for those transfers. Purchase, issuance and settlement activity in Level 3 is required to be disclosed on a gross basis. Fair value measurement disclosures are required for each class of assets and liabilities. These classes are a matter of management judgment. The guidance further requires disclosures about inputs and valuation techniques used for both Level 2 and Level 3 fair value measurements. This guidance became effective fiscal year 2011 with the exception of the gross disclosure of purchase, issuance and settlement activity in Level 3, which will be effective in fiscal year 2012. BPA adopted this guidance (with the exception of that relating to the gross disclosure of purchase, issuance and settlement activity in Level 3) on Oct. 1, 2010, with no material impact on its financial condition, results of operations or cash flows. BPA does not expect any significant impact from the guidance for the gross disclosure of purchase, issuance and settlement activity in Level 3 on BPA’s financial statements.

In May 2011, the FASB issued authoritative guidance which made a number of incremental changes to current fair value measurement and disclosure guidance. Changes with potential relevance to BPA include the clarification of the concept of “highest and best use” in fair value measurements, guidance on when financial instruments may be recorded on a net basis, and certain additional required disclosures for fair value measurements. The guidance will be effective for fiscal year 2012. BPA is evaluating the impact on BPA’s financial statements.

Variable interest entities

In June 2009, the FASB issued authoritative guidance that updated and amended consolidation accounting standards. The accounting standards update replaced the quantitative approach for determining who has the controlling financial interest in a variable interest entity (VIE) with a qualitative approach and requires ongoing assessments of an entity’s relationship with a VIE. BPA adopted this guidance on Oct. 1, 2010. The adoption of this guidance had no impact to BPA’s financial condition, results of operations or cash flows.

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties or whose equity investors lack any characteristics of a controlling financial interest. An entity has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to a VIE and the power to direct the activities that are most significant to a VIE's economic performance. An enterprise that has a controlling financial interest is known as the VIE's primary beneficiary and is required to consolidate the VIE.

BPA conducted a detailed review and analysis of agreements with counterparties that may be considered VIEs under this new standard. BPA determined it may transact with VIEs when it executes power purchase agreements. These VIEs are typically legal entities structured to own and operate specific generating facilities, primarily wind farms. The power purchase agreements could lead to BPA having a variable interest in the VIE if the agreements provide that BPA absorb risk from the perspective of the VIE. BPA has a number of power purchase agreements, which, because of their pricing arrangements, provide that BPA absorb commodity price risk of the counterparty entities. BPA does not provide, and does not plan to provide, any additional financial support to these entities beyond what BPA is contractually obligated to pay. BPA has concluded that in no instance does it have the power to control the most significant activities of these entities as the result of a power purchase agreement, and, as such, in no instance is BPA the primary beneficiary. BPA does not have control over the operating and maintenance activities that most significantly impact these entities. As a result of this review, BPA has not recorded any assets or liabilities related to the power purchase agreements with these entities and BPA has not consolidated any entities because of power purchase agreements.

BPA also reviewed the arrangements with the five NIFC entities and determined that BPA remains the primary beneficiary of these VIEs. BPA therefore continues to consolidate the NIFC entities into the FCRPS financial statements. (See Note 8, Nonfederal Financing.)

SUBSEQUENT EVENTS

FCRPS has performed an evaluation of events and transactions for potential recognition or disclosure through Oct. 27, 2011, which is the date the financial statements were issued.

2. Investments in U.S. Treasury Securities

As of Sept. 30 — thousands of dollars	**2011**		2010	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Short-term	**$ 253,348**	**$ 253,656**	$ 65,783	$ 66,090
Long-term	**39,129**	**40,712**	82,328	85,132
Total	**$ 292,477**	**$ 294,368**	$ 148,111	$ 151,222

In fiscal year 2009, BPA began participating in the U.S. Treasury's Federal Investment Program. Through this program, the U.S. Treasury provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and have legislative authority to invest those funds. Investments of the funds are generally restricted to special non-marketable securities, also called market-based specials. Under its banking arrangement with the U.S. Treasury, BPA has agreed to invest $100 million annually for up to 10 years or until the BPA fund is fully invested. Any remaining balance in the BPA fund at the 10th year will be invested through the Federal Investment Program.

Market-based specials held during fiscal years 2011 and 2010 had a weighted-average yield of 0.8 percent and 1.3 percent, respectively, and maturities of up to five years. The amounts shown in the table above exclude

U.S. Treasury securities with maturities of 90 days or less at the date of investment, which are considered cash equivalents and are included in the Combined Balance Sheets as part of Cash and cash equivalents. For all other securities, BPA follows the authoritative guidance for Investments, Debt and Equity Securities. These investments are classified as held-to-maturity and reported at amortized cost. Investments with maturities that will be realized in cash within one year are classified as short-term investments. Long-term investments have stated maturities between one and three years from the balance sheet date.

3. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars	**2011**	2010
REP Scheduled Amounts	$ **3,074,870**	$ —
Terminated nuclear facilities	**2,986,393**	3,377,550
REP Refund Amounts	**565,359**	—
Columbia River Fish Mitigation	**469,783**	436,912
Conservation measures	**272,924**	171,233
Fish and wildlife measures	**246,480**	180,256
Settlements	**50,428**	49,828
Federal Employees' Compensation Act	**31,352**	29,945
Derivative instruments	**27,422**	51,563
Trojan decommissioning and site restoration	**23,506**	24,152
Spacer damper replacement program	**21,853**	35,995
Terminated hydro facilities	**21,740**	22,785
Capital bond premiums	**10,554**	11,431
Sponsored conservation	**8,615**	21,865
REP Lookback Amount from IOUs	—	568,542
Other	**1,079**	1,085
Total	**$ 7,812,358**	$ 4,983,142

Regulatory assets include the following items:

"REP Scheduled Amounts" reflect the costs of future REP Scheduled Amounts representing REP benefits payable under the 2012 REP Settlement Agreement that will be recovered through rates. (See Note 9, Residential Exchange Program.)

"Terminated nuclear facilities" include the nonfederal debt for Energy Northwest Nuclear Project Nos. 1 and 3. These assets are amortized over the term of the related outstanding debt. (See Note 8, Nonfederal Financing.)

"REP Refund Amounts" is the amount recoverable in future rate periods that reduces the REP benefit payments. These costs will be recovered through future rates as reductions to IOU REP benefits as established in the 2012 REP Settlement Agreement. (See Note 9, 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 are recovered through 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.

"Fish and wildlife measures" consist of capitalized fish and wildlife projects and are amortized over a period of 15 years.

"Settlements" reflect costs related to settlement agreements resulting from litigation. These costs will be recovered and amortized through future rates over a period as established by the administrator.

"Federal Employees' Compensation Act" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.

"Derivative instruments" reflects the unrealized losses from BPA's derivative instruments that are marked-to-market in accordance with current authoritative derivative accounting guidance. (See Note 11, Risk Management and Derivative Instruments.) These amounts are deferred over the corresponding underlying contract delivery months.

"Trojan decommissioning and site restoration" costs reflect the amount to be recovered in future rates for funding the Trojan asset retirement obligation (ARO) liability. (See Note 4, Asset Retirement Obligations.)

"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 Damper Replacement Program. These costs are being amortized over a period of 30 years. In fiscal year 2011, BPA recognized an impairment charge of $20.6 million in deferred spacer damper replacement program costs.

"Terminated hydro facilities" include the nonfederal debt for the terminated Northern Wasco hydro project. These assets are amortized as the principal on the outstanding debt is repaid.

"Capital bond premiums" are losses related to refinanced debt and are amortized over the life of the new debt instruments.

"Sponsored conservation" relates to the nonfederal debt for Conservation and Renewable Energy System (CARES) 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 debt is repaid.

"REP Lookback Amount from IOUs" is the amount that was recoverable from IOUs in future rate periods that reduces their REP benefit payments. This regulatory asset was eliminated with the 2012 REP Settlement Agreement. (See Note 9, Residential Exchange Program.)

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars	**2011**	2010
Capitalization adjustment	**$ 1,601,796**	$ 1,666,701
REP Refund Amounts to COUs	**565,359**	—
Accumulated plant removal costs	**201,266**	186,764
CGS decommissioning and site restoration	**51,409**	48,530
Derivative instruments	**30,924**	17,701
REP Lookback Amount to COUs	—	568,542
Other	**5,589**	5,781
Total	**$ 2,456,343**	$ 2,494,019

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 2011, 2010 and 2009, respectively. (See Note 6, Federal Appropriations.)

"REP Refund Amounts to COUs" is the amount previously collected through rates that is owed qualifying consumer-owned utilities and will be credits on their future bills. These costs will be repaid and amortized through future rates over a period as established in the 2012 REP Settlement Agreement. (See Note 9, Residential Exchange Program.)

"Accumulated plant removal costs" is the amount previously collected through rates as part of depreciation. These costs will be relieved as actual removal costs are paid.

"CGS decommissioning and site restoration" is the amount previously collected through rates in excess of the ARO balances for CGS decommissioning and site restoration as well as Project Nos. 1 and 4 sites.

"Derivative instruments" reflects the unrealized gains from BPA's derivative instruments that are marked-to-market in accordance with current authoritative derivative accounting guidance. (See Note 11, Risk Management and Derivative Instruments.) These amounts are deferred over the corresponding underlying contract delivery months.

"REP Lookback Amount to COUs" is the amount that was previously collected through rates that is owed qualifying consumer-owned utilities and will be credits on their future bills. This regulatory liability was eliminated with the 2012 REP Settlement Agreement. (See Note 9, Residential Exchange Program.)

4. Asset Retirement Obligations

As of Sept. 30 — thousands of dollars	**2011**	2010
Beginning Balance	**$ 170,334**	$ 162,943
Activities:		
Accretion	**8,640**	8,324
Expenditures	**(2,234)**	(1,806)
Revisions	**(528)**	873
Ending Balance	**$ 176,212**	$ 170,334

BPA recognizes AROs according to the estimated fair value of the dismantlement and restoration costs associated with the retirement of certain tangible long lived assets. The liability is adjusted for any revisions, expenditures and the passage of time. FCRPS also has tangible long lived assets such as federal hydro projects without an associated ARO since no future obligation exists to remove these projects.

AROs include the following items as of Sept. 30, 2011:

- CGS decommissioning and site restoration of $133.3 million;
- Trojan decommissioning of $23.5 million;
- Energy Northwest Project Nos. 1 and 4 site restoration of $16.1 million;
- BPA owned transmission assets of $3.3 million.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — thousands of dollars	**2011**		2010	
	Amortized cost	**Fair value**	Amortized cost	Fair value
U.S. government obligation mutual funds	**$ 84,050**	**$ 86,834**	$ 101,142	$ 105,999
Equity index funds	**77,097**	**74,923**	77,413	80,867
Corporate bond index funds	**36,834**	**37,028**	1,949	1,954
Cash and cash equivalents	**24**	**24**	30	30
Total	**$ 198,005**	**$ 198,809**	$ 180,534	$ 188,850

BPA 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. External trust funds for decommissioning and site restoration costs are 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 the 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. The trusts are funded and managed by BPA in accordance with the NRC requirements and site certification agreements.

The investment securities in the decommissioning and site restoration trust are classified by BPA as available-for-sale in accordance with accounting guidance related to Investments, Debt and Equity Securities. Payments to the trusts for fiscal years 2011, 2010 and 2009 were approximately $9.6 million, $8.8 million and $8.2 million, respectively.

Based on an agreement in place 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.

5. Deferred Charges and Other

As of Sept. 30 — thousands of dollars	**2011**	2010
Special purpose corporations' trust funds	**$ 155,301**	$ 117,212
Derivative instruments	**32,380**	20,682
Spectrum Relocation fund	**15,884**	23,603
Trust fund and other deposits	**11,341**	639
Energy receivable	**5,334**	3,953
Other	**3,496**	3,229
Total	**$ 223,736**	$ 169,318

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, debt service payments during the construction period and a fund mainly for future principal and interest debt service payments. (See Note 8, Nonfederal Financing.)

"Derivative instruments" represent unrealized gains from the derivative portfolio which includes physical power purchase and sale transactions, power exchange 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 held in the BPA fund and are restricted for use in constructing replacement assets.

"Trust fund and other deposits" primarily represents funds held in the CARES defeasance trust fund.

"Energy receivable" primarily consists of energy to be returned to BPA for prior transmission line losses.

6. Federal Appropriations

Appropriations consist primarily of the power portion of Corps and Reclamation capital investments 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 System Act of 1974, 16 U.S.C. 838(j).

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 $6.69 billion were subsequently refinanced for $4.10 billion. This adjustment was recorded as a capitalization adjustment in regulatory liabilities and is being amortized over the remaining period of repayment. (See Note 3, Effects of Regulation.)

Federal generation and transmission appropriations are repaid to the U.S. Treasury within the weighted-average service lives of the associated investments from the time each facility was placed in service, with a maximum of 50 years. Federal appropriations may be paid early without penalty.

The weighted-average interest rate was 6.3 percent and 6.4 percent on outstanding appropriations as of Sept. 30, 2011, and 2010, respectively.

MATURING FEDERAL APPROPRIATIONS

As of Sept. 30 — thousands of dollars	
2012	$ 24,622
2013	18,250
2014	19,198
2015	54,788
2016	—
2017 and thereafter	4,232,645
Total	**$ 4,349,503**

7. Borrowings from U.S. Treasury

BPA is authorized by Congress to issue to the U.S. Treasury and have outstanding at any one time, up to $7.70 billion of interest bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. The debt may be issued to finance BPA's capital programs, which include Corps and Reclamation direct funded capital investments. Of the $7.70 billion, $750 million can be issued to finance Northwest Power Act related expenses and $1.25 billion is restricted for conservation and renewable resources.

At Sept. 30, 2011, of the total $2.94 billion of outstanding bonds, $252.8 million were conservation and renewable resources investments. There were no outstanding bonds with variable rates of interest at Sept. 30, 2011. At Sept. 30, 2010, $45.0 million of outstanding bonds carried a variable interest rate. The weighted-average interest rate of BPA's borrowings from the U.S. Treasury exceeds current rates. As a result, the fair value of BPA's U.S. Treasury borrowings exceeded the carrying value by approximately $462.6 million and $323.7 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2011, and 2010, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 4.2 percent and 4.4 percent as of Sept. 30, 2011, and 2010, respectively. At Sept. 30, 2010, the outstanding bonds with a variable rate of interest carried an interest rate of 0.2 percent.

U.S. Treasury borrowings of $2.47 billion are callable by BPA through Jan. 31, 2014. Of this amount, $35.0 million is callable at 100 percent of the principal value and the remainder is callable at a premium or discount, which is calculated based on the current government agency rates for the remaining term to maturity at the time the bond is called.

MATURING BORROWINGS FROM U.S. TREASURY

As of Sept. 30 — thousands of dollars	
2012	$ 265,000
2013	122,800
2014	103,000
2015	80,000
2016	30,000
2017 through 2039	2,342,640
Total	**$ 2,943,440**

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars	**2011**	2010
Terminated nuclear facilities:		
Nuclear Project No. 1	**$ 1,573,805**	$ 1,739,835
Nuclear Project No. 3	**1,495,480**	1,637,715
Terminated nuclear facilities	**3,069,285**	3,377,550
Nonfederal generation:		
Columbia Generating Station	**2,487,355**	2,327,455
Cowlitz Falls	**116,780**	122,410
Nonfederal generation	**2,604,135**	2,449,865
Lease financing program	**559,556**	449,695
Sponsored conservation:		
Conservation and Renewable Energy System	**11,200**	13,685
Tacoma	**6,675**	8,180
Sponsored conservation	**17,875**	21,865
Northern Wasco	**21,740**	22,785
Total	**$ 6,272,591**	$ 6,321,760

Prior to commercial operations, BPA acquired 100 percent and 70 percent of the generating capability of Energy Northwest’s Nuclear Project No. 1 and Nuclear Project No. 3, respectively. The contracts require BPA to cover the costs of all maintenance expense and debt service on debt issued by nonfederal entities. Nuclear Project No. 1 and Nuclear Project No. 3 were terminated prior to completion.

BPA acquired all of the generating capability and agreed to pay the operating, maintenance and debt service costs of Energy Northwest's CGS nuclear generating project and of Lewis County PUD's Cowlitz Falls Hydroelectric Project.

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

The underlying debt for the Energy Northwest obligations (comprising terminated nuclear facilities and CGS) matures through 2024 with interest rates that are fixed between 2.5 percent and 7.1 percent. Energy Northwest debt of $1.37 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2013 and July 2021 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded recorded value by $672.7 million and $714.6 million as of Sept. 30, 2011, and 2010, respectively. The valuations are based on a market input evaluation pricing methodology using a combination of market observable data such as current market trade data, reported bid/ask spreads and institutional bid information. The weighted-average interest rate was 5.1 percent and 5.2 percent for the Energy Northwest CGS, Nuclear Project No. 1, and Nuclear Project No. 3 portion of outstanding nonfederal debt as of Sept. 30, 2011, and 2010, respectively.

Under the Lease Financing Program, BPA consolidates five special purpose corporations, collectively referred to as Northwest Infrastructure Financing Corporations (NIFCs), which issue debt to and receive advances from nonfederal sources. The combined NIFCs have issued $119.6 million in bonds and borrowed $440.0 million on lines of credit with various banks. The bonds bear interest at 5.4 percent per annum and mature in 2034. All NIFC bonds outstanding are subject to redemption by NIFC, in whole or in part, at any date, at the higher of the principal amount of the bonds or the present value of the bonds discounted using the U.S. Treasury rate plus a premium of 12.5 basis points. The lines of credit become due in full at various dates ranging between July 1, 2014, and July 1, 2016. On the accompanying Combined Balance Sheets, the bonds and bank credit facilities are included in Nonfederal debt and the leased assets are primarily included in Utility plant and also in Deferred charges and other for unspent funds.

The fair value of the combined NIFC bonds and lines of credit exceeded the recorded value by $45.0 million and $33.3 million as of Sept. 30, 2011, and Sept. 30, 2010, respectively. The valuations are based on the discounted future cash flows using interest rates for similar debt which could have been issued at Sept. 30, 2011, and 2010, respectively. The weighted-average interest rate on the NIFCs' outstanding debt was 4.0 percent and 4.6 percent as of Sept. 30, 2011, and Sept. 30, 2010, respectively.

BPA has agreed to fund debt service on Conservation and Renewable Energy System and City of Tacoma Conservation bonds issued to finance conservation programs sponsored by BPA.

The Northern Wasco Hydro Project agreement was terminated by the Settlement and Termination Agreement between BPA and the Northern Wasco PUD on April 25, 1995. The Settlement Agreement requires BPA to pay the trustee annual debt service as required by the Bond Resolution.

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 $328.1 million, $262.6 million and $291.0 million in fiscal years 2011, 2010 and 2009, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $625.0 million, $600.4 million and $501.4 million for fiscal years 2011, 2010 and 2009, respectively, is reflected as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

2012	$ 429,545
2013	494,915
2014	714,842
2015	791,136
2016	841,187
2017 and thereafter	3,000,966
Total	**$ 6,272,591**

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.

VARIABLE INTEREST ENTITIES

Upon adoption of the update to consolidation accounting, BPA reviewed the arrangements with the five NIFC entities and determined that BPA continues to be the primary beneficiary of these VIEs. The key factor in this determination is BPA's ability to direct the commercial and operating activities of the transmission facilities underlying the lease agreements. Additionally, BPA's lease agreements with the NIFC entities obligate BPA to absorb the operational and commercial risks, and thus potentially significant benefits or losses, associated with the underlying transmission facilities.

Under the lease purchase agreements, the NIFCs issue debt to finance the construction of the transmission facilities which are then leased to BPA. The collateral for the debt is the lease payment stream from BPA. The NIFC entities hold legal title to the transmission facilities during the lease term and BPA serves as the construction agent for these leased assets. BPA also has exclusive use and control of the assets during the lease periods and has indemnified the equity owners of the NIFCs for all construction and operating risks associated with the leased transmission facilities. At the end of each lease term, BPA has the option to buy the transmission facilities at a bargain purchase price. BPA provides certain administrative services as construction agent to the NIFCs and is obligated to indemnify certain expenses of the NIFCs related to their respective projects.

Amounts related to the NIFC entities included on the Combined Balance Sheets include Deferred charges and other of $33.5 million and $28.8 million and Nonfederal debt of $559.6 million and $449.7 million as of Sept. 30, 2011, and 2010, respectively.

9. Residential Exchange Program

BACKGROUND

As provided in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), beginning in 1981 BPA entered into 20-year Residential Purchase and Sale Agreements (RPSAs) with eligible regional utility customers. The RPSAs implemented the REP.

In 2000, BPA signed Residential Exchange Program Settlement Agreements ("REP settlements" or "settlement agreements") with the region's six IOUs under which BPA provided 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 with IOU customers related to the settlement agreements. 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 IOU monetary benefits for fiscal years 2007 through 2011, provided that BPA would have no obligation to provide power to the IOUs in this period. When future amounts were committed through these agreements, BPA recorded a REP settlement liability for the minimum committed amounts and a regulatory asset for amounts recoverable in future rates.

LOOKBACK AMOUNT

In May 2007, the Ninth Circuit Court ruled that the REP settlements were inconsistent with the Northwest Power Act and that BPA improperly allocated settlement costs to BPA's preference rates. In response to that ruling, in fiscal year 2008 BPA reduced the REP settlement agreement liability and regulatory asset to zero and conducted the 2007 Supplemental Wholesale Power Rate Case (WP-07 Supplemental Rate Case).

On Sept. 22, 2008, the BPA administrator issued a Final Record of Decision (ROD) that revised power rates for fiscal year 2009 and determined the amount the COUs were overcharged in prior years. A portion of the prior overcharges, which amounted to $746.2 million for fiscal years 2002 through 2006, were labeled the "Lookback Amount" in the Final ROD. This Lookback Amount represented amounts over-collected from COUs in prior years' rates, which also represented the amounts overpaid to the IOUs under the settlement agreements in prior years. As described in the WP-07 Supplemental Rate Case and in the 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (WP-10 Rate Case), the BPA administrator designated the amount to be recovered from each IOU and returned to the qualifying COUs. These amounts did not reduce rates, but were applied as credits to qualifying COUs as designated in the corresponding Final RODs. BPA recognized the refund and reduced expense in the year it was applied. These transactions were net revenue neutral as the same amount reduced both revenue and expense. The Lookback Amount was recorded as both a regulatory asset, representing amounts to be collected from IOUs through future rate proceedings, and a regulatory liability, representing amounts to be credited to the COUs in future rates.

After recording the Lookback Amount for fiscal year 2010 of $82.1 million, the Lookback Amount ending balance including interest as of Sept. 30, 2010, was $568.5 million. In 2011, BPA adjusted both the regulatory liability and regulatory asset to $565.4 million to reflect the changes resulting from the 2012 Settlement Agreement.

IOU EXCHANGE BENEFITS

In fiscal year 2008, Interim Agreements were executed to provide certain IOUs with temporary REP benefits for their residential and small farm consumers. These agreements included a provision to true up the amounts advanced with the actual REP benefits for fiscal year 2008. The true up amount for the IOUs was $69.6 million; however, provisions in the agreement provided that true up payments could not be paid until any subsequent legal challenges to BPA's final ROD, if any, are resolved. (See Note 13, Commitments and Contingencies.) As yet, all legal challenges related to this program have not been resolved.

In 2009, BPA reached a settlement with Avista over its disputed deemer balance, which resulted in the amount due to it for its 2008 benefits changing from zero to $12.0 million and an increase in the IOU exchange benefits balance to $81.6 million. After applying interest for fiscal year 2011, this balance has increased to $86.4 million.

2009 DEEMER ADJUSTMENT

As noted above, in June 2009, BPA reached a settlement regarding a long standing dispute with Avista Corporation over the REP deemer account provisions. Deemer balances result when a REP exchanging utility's average system cost is below the BPA priority firm exchange rate. Rather than resulting in a requirement of the exchanging utility to pay BPA for the exchange, the utility deems its average system cost to be equal to the priority firm exchange rate. The amount that otherwise would have been owed to BPA is accumulated and offset against future benefits until the deemer account is reduced to zero. Upon elimination of the deemer account balance, the exchanging utility is entitled to receive payment for exchange benefits. The settlement with Avista set the beginning fiscal year 2002 deemer balance to $55.0 million, rather than the disputed deemer account balance of $85.6 million.

The accumulated effect of the Avista settlement resulted in higher REP expense recorded in fiscal year 2009 of $20.5 million and lower revenues due to the effect of the Avista Lookback Amount applied of $12.5 million that was recorded as revenue subject to refund. The total effect was a reduction to Net revenue of $33.0 million for fiscal year 2009.

2012 RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT

Beginning in April 2010, over 50 litigants and other regional parties entered into mediation to resolve their numerous disputes over the REP. Participants reached an agreement in principle in early September 2010 and in February 2011 reached a final settlement agreement – the 2012 Residential Exchange Program Settlement Agreement (Settlement Agreement). In March 2011, BPA distributed the Settlement Agreement for regional entities' consideration and signature. In conjunction with the customers' settlement agreement efforts, in December 2010 BPA initiated the Residential Exchange Program Settlement Agreement Proceeding (REP-12) to evaluate the Settlement Agreement and determine whether it was in the region's best interest for the administrator to sign the Settlement Agreement on behalf of BPA. In July 2011, the administrator signed the REP-12 Final ROD and the Settlement Agreement.

In 2011, BPA recorded a long-term liability and corresponding regulatory asset of $3.07 billion associated with the Settlement Agreement. Beginning in fiscal year 2012, under the provisions of the Settlement Agreement the IOUs receive Scheduled Amounts starting at $182.1 million with increases over time to $286.1 million as the final payment in fiscal year 2028. The distribution of these payments will depend on each IOUs' average system cost and exchange load, plus adjustments to reflect Lookback Amounts recovered from IOUs in fiscal years 2009 through 2011. The settled Scheduled Amounts to be paid to the IOUs total $4.07 billion over the 17-year period. Amounts recorded of $3.07 billion represent the present value of future cash outflows for these exchange benefits.

In addition to Scheduled Amounts, the Settlement Agreement calls for Refund Amounts to be paid of $76.5 million each year beginning in fiscal year 2012 through fiscal year 2019. The Refund Amounts replace the Lookback Amounts and are accounted for similar to the Lookback Amounts in that a regulatory asset and liability have been established for the refunds that will be provided to BPA customers as credits on customer monthly bills. The Settlement Agreement replaces the Lookback Amounts that were reduced to zero as of Sept. 30, 2011, with the Refund Amounts totaling $612.3 million. Amounts recorded of $565.4 million represent the present value of future cash flows for the amounts to be refunded to customers, as well as reduced exchange benefits. The distribution of the Refund Amount will be split between customers with 50 percent of the Refund Amounts ($38.3 million per year) returned to COUs based on the percentages BPA established in the WP-10 rate proceeding. The remaining 50 percent will be returned to COUs based on each customer's expected share of Tier 1 load as defined in BPA's 2012 Wholesale Power and Transmission Rate Adjustment Proceeding.

10. Deferred Credits and Other

As of Sept. 30 — thousands of dollars	**2011**	2010
Generation interconnection agreements	**$ 279,048**	$ 251,206
Customer reimbursable projects	**238,317**	233,045
Third AC Intertie capacity agreements	**101,221**	103,904
Capital leases	**35,619**	36,652
Fiber optic leasing fees	**32,722**	35,371
Federal Employees' Compensation Act	**31,352**	29,945
Settlements	**28,500**	28,500
Derivative instruments	**27,422**	51,563
Other	**7,906**	13,272
Total	**$ 782,107**	$ 783,458

Deferred credits and other include the following items:

"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.

"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.

"Third AC Intertie capacity agreements" reflect unearned revenue from customers related to the Third AC Intertie capacity project. Revenue is being recognized over an estimated 49-year life of the related assets.

"Capital leases" represent BPA's long-term portion of capital lease liabilities that are not part of the Lease Financing Program. (See Note 8, Nonfederal Financing.)

"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 amounts accrued to settle outstanding litigation. (See Note 13, Commitments and Contingencies.)

"Derivative instruments" reflect the unrealized fair value loss of the derivative portfolio which includes physical power purchase and sale transactions and a heat rate option contract.

11. Risk Management and Derivative Instruments

BPA is exposed to various forms of market risk including commodity price risk, commodity volumetric risk, interest rate risk, credit risk and event risk. Non-performance risk, which includes credit risk, is described in Note 12, Fair Value Measurements. BPA has formalized risk management processes in place to manage agency risks, including the use of derivative instruments. The following describes BPA's exposure to and management of risks.

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and electric market prices, net revenues that result from underlying surplus or deficit energy positions are inherently uncertain. BPA's Transacting Risk Management Committee has responsibility for the oversight of market risk and determines the transactional risk policy and control environment at BPA. Through simulation and analysis of the hydro supply system, experienced business and risk managers install market price risk measures to capture additional market related risks, including credit and event risk.

COMMODITY PRICE RISK AND VOLUMETRIC RISK

Primarily due to the variation in the available energy from its hydroelectric generation capacity, BPA enters into short-term and long-term forward sales and purchase agreements in the wholesale markets to balance its energy supply and demand. Commodity price risk results from fluctuations in the electric market prices in the Pacific Northwest that affects the value of the energy inventory bought and sold, as well as the value of prior purchase and sale contracts. In fiscal year 2011, there was a net surplus and sale of energy above that needed to serve the region's firm load obligations.

BPA measures the market price risk in its portfolio on a daily, weekly and monthly basis employing both parametric calculations and non-parametric Monte Carlo simulations to derive net revenues at risk, mark-to-market, value at risk and additional risk metrics as appropriate. These methods provide a consistent measure of risk across the energy market in which BPA buys and sells. The use of these methods requires a number of key assumptions including hydro/price correlations, the selection of a confidence level for expected losses, the holding period for liquidation and the treatment of risks outside standard measures such as sensitivity and scenario testing to determine the impacts of a sudden change in market price, volatility, correlations or hydro inventory. These methods assume hypothetical movements in future market prices and in hydro inventory and provide an estimate of possible net revenues outcomes for BPA's portfolios. In response to market price risk, futures, forwards, swaps and option instruments may be used to mitigate BPA's exposure to price fluctuations.

CREDIT RISK

Credit risk relates to the risk of loss that might occur as a result of non-performance by counterparties of their obligations to deliver or take delivery of electricity. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. To further manage credit risk, BPA obtains credit support such as letters of credit, parental guarantees, cash in the form of prepayment and/or deposit of escrow from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly. BPA uses internally developed, commercially appropriate rating methodologies, credit scoring models, publicly available information and external ratings from major credit rating agencies to determine the public rating equivalent grade of counterparties.

During fiscal year 2011, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings. At Sept. 30, 2011, BPA had $43.1 million in credit exposure to purchase and sale contracts taking into account netting rights. BPA's credit exposure, net of cash collateral, to sub-investment grade counterparties was less than one percent of total outstanding credit exposures. BPA's top five credit exposures were $34.8 million, or 80.7 percent, of the total credit exposure. The majority of this exposure is mark-to-market exposure arising from a term transaction with an "AA-" rated municipality with ratemaking authority.

INTEREST RATE RISK

BPA has the ability to issue variable rate debt to the U.S. Treasury. As of Sept. 30, 2011, BPA had no outstanding variable rate U.S. Treasury debt. (See Note 7, Borrowings from U.S. Treasury.)

DERIVATIVE INSTRUMENTS

BPA follows the Derivatives and Hedging accounting guidance that requires 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.

COMMODITY CONTRACTS

It is BPA's policy to document and apply as appropriate the normal purchases and normal sales exception allowed under Derivatives and Hedging accounting guidance. Forward electricity contracts are generally considered normal purchases and normal sales if they 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 the Derivatives and Hedging accounting guidance. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

In fiscal year 2010, BPA began applying Regulated Operations accounting treatment to its derivative instruments that are recorded at fair value and do not meet the normal purchases and normal sales exception. As a result, BPA recognized a loss of $16.4 million in fiscal year 2010 which was primarily comprised of the net derivative balance for commodity contracts at the beginning of the year.

Prior to this adoption, BPA recorded the changes in fair value under Derivative instruments 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. (See Note 12, Fair Value Measurements.)

At Sept. 30, 2011, the derivative commodity contracts recorded at fair value totaled 10.4 million MWh (gross basis). BPA records realized and unrealized gains and losses on commodity contract derivative transactions in the operating section as non-cash adjustments in the Combined Statements of Cash Flows. BPA does not apply hedge accounting.

INTEREST RATE SWAP TRANSACTIONS

In fiscal year 2010, BPA terminated two floating-to-fixed LIBOR interest rate swaps which had been used to help manage interest rate risk related to its long-term variable Energy Northwest debt portfolio. BPA terminated both swaps in conjunction with its debt management action to refinance the related variable rate debt into fixed rate debt. This resulted in the realization of a $29.4 million loss, which was included in nonfederal projects expenses, and the corresponding removal of the $31.2 million unrealized loss from Derivative instruments under Operating revenues.

DERIVATIVE ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

As of Sept. 30 — thousands of dollars	**2011**	2010
Assets		
Derivative instruments [1]		
Commodity contracts, gross	**$ 47,140**	$ 22,829
Less: netting [2]	**(14,760)**	(2,147)
Total, net	**$ 32,380**	$ 20,682
Liabilities		
Derivative instruments [1]		
Commodity contracts, gross	**$ (42,182)**	$ (53,710)
Less: netting [2]	**14,760**	2,147
Total, net	**$ (27,422)**	$ (51,563)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 10, Deferred Credits and Other.)
[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

Derivative instruments unrealized gains of $37.4 million and unrealized losses of $33.9 million were recorded in regulatory assets and liabilities in the Combined Balance Sheets in fiscal years 2011 and 2010, respectively. The following table presents the effect of derivative instruments gains and losses on the Combined Statements of Revenues and Expenses.

AMOUNT OF GAIN (LOSS) RECOGNIZED

As of Sept. 30 —- thousands of dollars	**Location of Gain (Loss) Recognized in Net Revenues (Expenses)**	**2011**	2010	2009
Commodity contracts	Derivative instruments	**$ —**	**$** (16,446)	$ (17,356)
Interest rate swaps	Derivative instruments	—	31,246	(18,680)
Subtotal		—	14,800	(36,036)
Interest rate swaps	Nonfederal projects	—	(29,422)	(7,450)
Total		$ —	$ (14,622)	$ (43,486)

12. Fair Value Measurements

BPA applies the Fair Value Measurements and Disclosures accounting guidance for all financial instruments (recurring and nonrecurring) and for all nonfinancial instruments subject to recurring fair value measurement. This accounting guidance defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and prescribes disclosures about fair value measurements. BPA applied fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and nuclear decommissioning trusts and other investments in accordance with the accounting guidance.

In accordance with the Fair Value Measurements and Disclosures accounting guidance, BPA maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value. Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, BPA seeks price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, BPA uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs.

BPA also utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that BPA has the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as fixed income, equity mutual funds and money market funds.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include certain non-exchange traded derivatives and certain agency securities as part of the special purpose corporations' trust funds investments.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 include long dated and modeled commodity contracts.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

In accordance with the Fair Value Measurements and Disclosures accounting guidance, BPA includes non-performance risk in calculating fair value measurements. This includes a credit risk adjustment based on the credit spreads of BPA's counterparties when in an unrealized gain position, or on BPA's own credit spread when in an unrealized loss position. BPA's assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at Sept. 30, 2011, and 2010.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2011 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
U.S. government obligation mutual funds	$ 86,834	$ —	$ —	$ —	**$ 86,834**
Equity index funds	74,923	—	—	—	**74,923**
Corporate bond index funds	37,028	—	—	—	**37,028**
Cash and cash equivalents	24	—	—	—	**24**
Derivative instruments [1]					
Commodity contracts	—	21,058	26,082	(14,760)	**32,380**
Special purpose corporations' trust funds					
U.S. government obligations	—	125,547	—	—	**125,547**
U.S. government sponsored enterprise obligations	—	1,052	—	—	**1,052**
Total	$198,809	$147,657	$ 26,082	$(14,760)	**$357,788**
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(40,743)	$ (1,439)	$ 14,760	**$(27,422)**
Total	$ —	$(40,743)	$ (1,439)	$ 14,760	**$(27,422)**

As of Sept. 30, 2010 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
U.S. government obligation mutual funds	$105,999	$ —	$ —	$ —	$105,999
Equity index funds	80,867	—	—	—	80,867
Corporate bond index funds	1,954	—	—	—	1,954
Cash and cash equivalents	30	—	—	—	30
Derivative instruments [1]					
Commodity contracts	—	2,329	20,500	(2,147)	20,682
Special purpose corporations' trust funds					
U.S. government obligations	—	89,012	—	—	89,012
U.S. government sponsored enterprise obligations	—	6,898	—	—	6,898
Total	$188,850	$ 98,239	$ 20,500	$ (2,147)	$305,442
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(50,865)	$ (2,845)	$ 2,147	$(51,563)
Total	$ —	$(50,865)	$ (2,845)	$ 2,147	$(51,563)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 10, Deferred Credits and Other.) See Note 11, Risk Management and Derivative Instruments for more information related to BPA's risk strategy and use of derivative instruments.

[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

COMMODITY CONTRACTS

The following table presents the changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

For the year ended Sept. 30 — thousands of dollars	**2011**	2010
Beginning Balance	**$ 17,655**	$ 28,190
Total realized and unrealized gains (losses) included in:		
Net revenues (expenses) [1]	—	(25,209)
Regulatory assets and liabilities [2]	**6,988**	14,674
Purchases, issuance and settlements	—	—
Transfers in (out) of Level 3	—	—
Ending Balance	**$ 24,643**	$ 17,655
The amount of total gains (losses) for the fiscal year included in Net revenues (expenses) attributable to the change in unrealized gains (losses) relating to contracts still held at the reporting date [1]	**$** —	$ (23,837)

[1] Prior to BPA's application of Regulated Operations accounting treatment to its derivative instruments in fiscal year 2010, unrealized gains and loses were included in Derivative instruments in the Combined Statements of Revenues and Expenses.
[2] Subsequent to BPA's application of Regulated Operations accounting treatment to its derivative instruments in fiscal year 2010, unrealized gains and losses are included in Regulatory assets and liabilities in the Combined Balance Sheets.

13. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

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 projects that are consistent with the Northwest Power Act and that are consistent with the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish species are listed 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 (BiOp) prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA. BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp is not fixed or determinable. However, the current estimate of long-term fish and wildlife agreements with a contractual commitment which BPA has entered into is $1.03 billion. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — thousands of dollars		
2012	**$**	1,182
2013		58,823
2014		52,427
2015		51,989
2016		60,814
2017 and thereafter		440,855
Total	**$**	**666,090**

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. In establishing power rates, particular statutory provisions guide the assumptions that BPA makes as to the amount and timing of such distributions. 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 are scheduled to total $666.1 million over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. BPA is required by the Grand Coulee Dam - Third Powerplant Act to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA 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 irrigators' ability 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 for which BPA has no obligation to recover these costs.

FIRM PURCHASE POWER COMMITMENTS

As of Sept. 30 — thousands of dollars		
2012	$	51,805
2013		66,441
2014		35,234
Total	$	**153,480**

When BPA forecasts a resource shortage based on expected obligations and the historical water record for the Columbia River basin, BPA takes a variety of steps to cover the shortage. If appropriate, BPA will enter into long-term commitments to purchase power for future delivery. The above table includes firm purchase power agreements of known cost that are currently in place to assist in meeting expected future obligations under long-term power sales contracts. Included are six contracts for winter purchases through fiscal year 2014 and three purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal years 2012 and 2013. The expense associated with the winter purchases for 2011 and 2010 were $43.4 million and $43.1 million, respectively. Delivery for Tier 2 purchases does not commence until fiscal year 2012. There were no purchases made under any of the contracts prior to 2010. BPA has several power purchase agreements with wind powered and other generating facilities that are not included in the table above as payments are based on the variable amount of future energy generated and there are no minimum payments required.

NUCLEAR INSURANCE

BPA is a member of the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company established to provide insurance coverage for nuclear power plants. The insurance policies purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decontamination Liability, Decommissioning Liability and Excess Property Insurance; and 3) NEIL I Accidental Outage Insurance.

Under each insurance policy, BPA could be subject to a retrospective premium 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 Liability Insurance policy is $9.1 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $18.7 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $5.0 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 $375.0 million, BPA could be subject to a retrospective assessment of up to $111.9 million limited to an annual maximum of $17.5 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. As such, no material liability has been recorded.

LITIGATION

Southern California Edison

Southern California Edison (SCE) filed two separate actions pending in the U.S. Court of Federal Claims against BPA related to a power sales and exchange 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); and 2) BPA's termination of the Sales and Exchange Agreement due to SCE's nonperformance (Termination Claim).

In 2006, BPA and SCE executed an agreement to settle the claims wherein BPA would make a payment of $28.5 million plus applicable interest to SCE if certain identified conditions were met, including a final resolution of BPA's claims pending in the California refund proceedings and related litigation. BPA has recorded a liability in this amount on the basis that all conditions have been met except the final resolution in the California refund proceedings which management considers probable. BPA established an offsetting regulatory asset, as the costs will be collected in future rates.

California parties' refund claims

BPA was a party to proceedings at FERC that sought refunds for sales into markets operated by the California Independent System Operator (ISO) and the California Power Exchange (PX) during the California energy crisis of 2000-2001. BPA, along with a number of other governmental utilities, challenged FERC's refund authority over governmental utilities. In BPA v. FERC, 422 F.3d 908 (9th Cir. 2005) the Court found that governmental utilities, like BPA, were not subject to FERC's statutory refund authority. As a consequence of the Court's decision, three California investor-owned utilities along with the State of California filed breach of contract claims in the United States Court of Federal Claims against BPA. The complaints, filed in March 2007, alleged that BPA was contractually obligated to pay refunds on transactions where BPA received amounts in excess of mitigated market clearing prices established by FERC. The plaintiffs' contractual breach is premised upon a FERC finding that it retroactively reset the prices under the ISO and PX tariffs when it established these mitigated market clearing prices. BPA has separately appealed to the Ninth Circuit Court the FERC finding that it retroactively reset the tariff prices. The plaintiffs' claims for relief exceed $300 million. A trial on the liability portion of plaintiffs' contractual breach claim commenced in July 2010 and concluded in August 2010. Post trial briefs were filed during fall 2010 and closing arguments were held in February 2011, and BPA is awaiting the Court's ruling. The damages phase of the case will be tried only after the Court of Federal Claims rules on the liability portion. No date has been scheduled for the damages phase.

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.

Currently pending before the Ninth Circuit Court are numerous challenges to the decisions BPA reached in the WP-07 Supplemental Rate Case and that were also incorporated in the WP-10 Rate Case. The petitioners in these cases challenge, among other issues, BPA's calculation of certain refunds (referred to as "Lookback Amounts") associated with rates charged to BPA's preference customers from fiscal years 2002 through 2008. These refunds resulted from BPA's implementation of an REP settlement in fiscal years 2002 through 2008 that was later found unlawful and payment of REP benefits to BPA's investor-owned utility customers under that settlement. Following extensive negotiations, representatives from most of the region's consumer- and investor-owned utilities reached a proposed agreement on how BPA should establish REP benefits and recover the costs of those benefits through rates for the fiscal year period 2002 through 2028. BPA conducted a formal evidentiary hearing to review the proposed settlement agreement, which was signed by the administrator on July 26, 2011. Since the 2012 REP Settlement Agreement completely replaces BPA's REP-related WP-07 Supplemental Rate Case and WP-10 Rate Case decisions, BPA and many consumer-owned utilities have filed a motion in Ninth Circuit Court to dismiss pending litigation challenging those decisions. Any changes in REP benefits or costs will be resolved through future rates. BPA has recorded regulatory assets, a liability and a regulatory liability for the effects of the Settlement Agreement. (See Note 9, Residential Exchange Program.)

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; however, BPA 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 2011.

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

APPENDIX B-2

Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Thousands of dollars)

	As of June 30, 2012	As of September 30, 2011
Assets		
Utility plant		
Completed plant	$ 14,885,626	$ 14,741,720
Accumulated depreciation	(5,574,216)	(5,436,160)
	9,311,410	9,305,560
Construction work in progress	1,744,886	1,396,097
Net utility plant	11,056,296	10,701,657
Nonfederal generation	2,609,358	2,604,078
Current assets		
Cash and cash equivalents	1,257,282	892,125
Short-term investments in U.S. Treasury securities	332,502	253,348
Accounts receivable, net of allowance	23,195	119,596
Accrued unbilled revenues	265,334	207,089
Materials and supplies, at average cost	98,531	93,924
Prepaid expenses	51,590	29,430
Total current assets	2,028,434	1,595,512
Investments and other assets		
Regulatory assets	7,485,428	7,812,358
Investments in U.S. Treasury securities	64,396	39,129
Nonfederal nuclear decommissioning trusts	226,423	198,809
Deferred charges and other	261,980	223,736
Total investments and other assets	8,038,227	8,274,032
Total assets	$ 23,732,315	$ 23,175,279
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	$ 2,683,863	$ 2,510,373
Federal appropriations	4,348,026	4,324,881
Borrowings from U.S. Treasury	3,118,440	2,678,440
Nonfederal debt	5,553,475	5,843,046
Total capitalization and long-term liabilities	15,703,804	15,356,740
Commitments and contingencies (See Note 13 to annual financial statements)		
Current liabilities		
Federal appropriations	24,622	24,622
Borrowings from U.S. Treasury	425,000	265,000
Nonfederal debt	553,489	429,545
Accounts payable and other	539,869	523,459
Total current liabilities	1,542,980	1,242,626
Other liabilities		
Regulatory liabilities	2,373,869	2,456,343
IOU exchange benefits	3,096,155	3,161,251
Asset retirement obligations	182,134	176,212
Deferred credits and other	833,373	782,107
Total other liabilities	6,485,531	6,575,913
Total capitalization and liabilities	$ 23,732,315	$ 23,175,279

Federal Columbia River Power System
Combined Statements of Revenues and Expenses (Unaudited)
(Thousands of dollars)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Fiscal Year-to-Date Ended June 30, 2012	Fiscal Year-to-Date Ended June 30, 2011
Operating revenues				
Sales	**$ 794,437**	$ 698,376	**$ 2,415,902**	$ 2,399,063
U.S. Treasury credits for fish	**16,673**	17,690	**58,397**	68,586
Miscellaneous revenues	**18,409**	14,756	**52,785**	45,884
Total operating revenues	**829,519**	730,822	**2,527,084**	2,513,533
Operating expenses				
Operations and maintenance	**440,258**	418,093	**1,304,126**	1,252,295
Purchased power	**7,430**	27,507	**113,612**	146,745
Nonfederal projects	**158,340**	165,651	**478,998**	461,143
Depreciation and amortization	**96,537**	97,625	**288,900**	292,839
Total operating expenses	**702,565**	708,876	**2,185,636**	2,153,022
Net operating revenues	**126,954**	21,946	**341,448**	360,511
Interest expense and (income)				
Interest expense	**85,858**	84,666	**244,210**	248,665
Allowance for funds used during construction	**(13,986)**	(10,417)	**(40,805)**	(28,974)
Interest income	**(7,636)**	(10,975)	**(35,447)**	(28,661)
Net interest expense	**64,236**	63,274	**167,958**	191,030
Net revenues (expenses)	**$ 62,718**	$ (41,328)	**$ 173,490**	$ 169,481

APPENDIX C

Report of Independent Auditors

To the Executive Board of Energy Northwest:

In our opinion, the financial statements of the business-type activities of Energy Northwest (the "Company"), including the Columbia Generating Station, Packwood Lake Hydroelectric Project, Nuclear Project No. 1, Nuclear Project No. 3, the Business Development Fund, the Nine Canyon Wind Project, and the Internal Service Fund which collectively comprise the Company's balance sheets, statements of revenues, expenses and changes in net assets, and of cash flows, present fairly, in all material respects, the respective financial position of the business-type activities of the Company at June 30, 2011, and the respective changes in financial position and cash flows, where applicable, thereof for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express opinions on these financial statements based on our audit. We conducted our audit 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 audit provides a reasonable basis for our opinions.

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
October 27, 2011

Energy Northwest Management's Discussion & 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, 2011, with the basic financial statements for the FY ended June 30, 2010.

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 standards prescribed by the Financial Accounting Standards Board (FASB). (See Note 1 to the Financial Statements.) Effective July 1, 2009, the FASB issued the Accounting Standards Codification (ASC). The ASC does not change GAAP and does not have an effect on Energy Northwest's financial position or results of operation. Technical references to GAAP included in this report are provided under the new ASC structure.

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 2011 and FY 2010 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 Revenues, Expenses, and Changes in Net Assets, and 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 for each business unit. (See Note 1 to the Financial Statements.)

The Statements of Revenues, Expenses, and Changes in Net Assets 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 investing activities. The Statements of Cash Flows 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 5 to the Financial Statements), accounting policies, significant balances and activities, material risks, commitments and obligations, and subsequent events, if applicable.

The basic financial statements of each business unit along with the notes to the financial statements and management discussion and analysis should be used 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, 2011 and 2010 (in thousands)

		2010		2011		Change
Assets						
Current Assets	$	189,918	$	225,932	$	36,014
Restricted Assets						-
Special Funds		93,454		118,860		25,406
Debt Service Funds		421,110		459,183		38,073
Net Plant		1,485,233		1,519,569		34,336
Nuclear Fuel		196,379		266,949		70,570
Deferred Charges		4,306,114		4,027,612		(278,502)
TOTAL ASSETS	**$**	**6,692,208**	**$**	**6,618,105**	**$**	**(74,103)**
Current Liabilities	$	374,924	$	435,218	$	60,294
Restricted Liabilities						
Special Funds		141,811		149,430		7,619
Debt Service Funds		145,396		150,832		5,436
Long-Term Debt		6,022,980		5,875,190		(147,790)
Other Long Term Liabilities		12,373		14,028		1,655
Deferred Credits		6,020		5,820		(200)
Net Assets		(11,296)		(12,413)		(1,117)
TOTAL LIABILITIES AND NET ASSETS	**$**	**6,692,208**	**$**	**6,618,105**	**$**	**(74,103)**
Operating Revenues	$	475,985	$	552,292	$	76,307
Operating Expenses		360,876		415,020		54,144
Net Operating Revenues		115,109		137,272		22,163
Other Income and Expenses		(113,498)		(138,790)		(25,292)
(Distribution) & Contribution		(650)		1,000		1,650
Beginning Net Assets		(12,856)		(11,895)		961
ENDING NET ASSETS	**$**	**(11,895)**	**$**	**(12,413)**	**$**	**(518)**

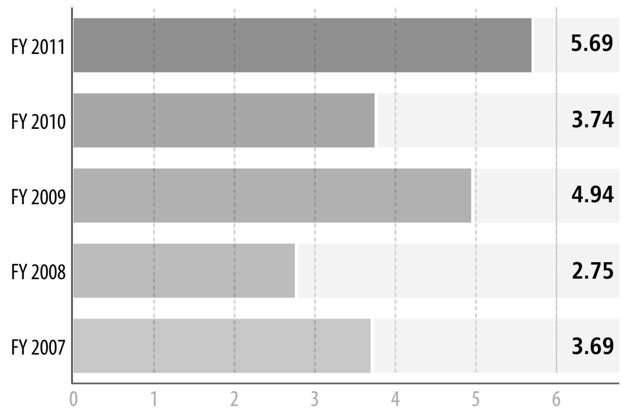
Columbia Generating Station

The Columbia Generating Station (Columbia) is wholly 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 plant located on the Department of Energy's (DOE) Hanford Site north of Richland, Wash.

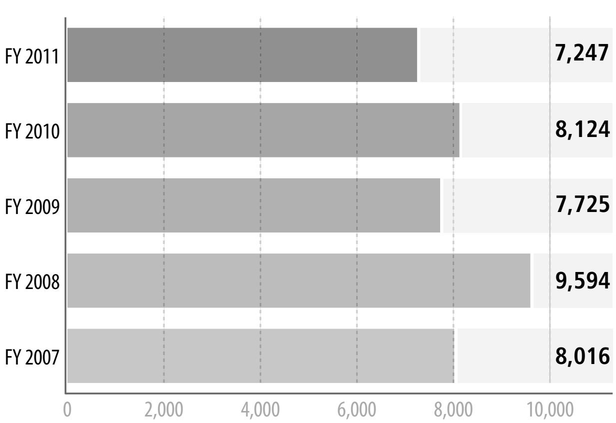
Columbia produced 7,247 gigawatt-hours (GWh) of electricity in FY 2011, as compared to 8,124 GWh of electricity in FY 2010, which included economic dispatch of 99 and 119 GWh respectively. Columbia set a record run of 505 days which ended when Columbia entered its longest planned refueling cycle (R-20) of 78 days on April 1. The planned outage extended past the 78 days and into September of FY 2012. The extended outage, along with the record run occurring mostly in FY 2010 were the factors in the decreased generation of 10.8 percent in FY 2011.

Columbia's cost performance is measured by the cost of power indicator. The cost of power for FY 2011, was 5.69 cents per kilowatt-hour (kWh) as compared with 3.74 cents per kWh in FY 2010. The industry cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. The cost of power increase of 52.1 percent from FY 2010 was due to the planned outage and the impact of the extension of the outage through the end of the fiscal year.

Columbia Generating Station
COST OF POWER - Cents/kWh



Columbia Generating Station
NET GENERATION - GWhrs



Balance Sheet Analysis

The net increase to Utility Plant (Plant) and Construction Work In Progress (CWIP) from FY 2010 to FY 2011 (excluding nuclear fuel) was $34.4 million. The additions to Plant/CWIP of $13.3 million were additions to Plant of $59.5 million offset by retirements of $86.0 million and an increase to CWIP of $39.8 million. The remaining change of $21.1 million to net Plant was a result of a decrease in accumulated depreciation for retirement of the main condenser unit, as part of R-20 ($61.0 million) and adjustment for a historical correction to accumulated depreciation and net book value of $34.3 million (See Note 2 to Financial Statements). These items were offset against the normal period impacts for FY 2011 of $66.6 million resulting in the net decrease to accumulated depreciation.

The gross addition of $101.1 million to CWIP in FY 2011 was captured in six major projects of at least $2.0 million: Main Condenser Replacement, Main Generator Rotor, Non-Segmented Bus Hardware, Turbine Blade Replacement, Main Transformer, and Cooling Tower Fill Replacement. These projects resulted in 81 percent of CWIP activity. The remaining 19 percent were made up of 100 separate projects.

Nuclear fuel, net of accumulated amortization, increased $70.6 million from FY 2010 to $267.0 million for FY 2011. Fuel amounts used for reload increased $47.8 million, fuel removed for cooling increased $53.5 million. These increases were offset by decreases in fuel loan amount of $3.4 million and $27.3 million in current year amortization.

Current assets increased $41.0 million in FY 2011 to $193.7 million. The main cause of this increase was due to timing of FY 2012 obligations due July 1 and timing of transfers between current and restricted funds. This resulted in an increase of $25.9 million. Decreases in normal year timing and obligations resulted in the remaining change of $0.3 million.

Special funds increased $26.3 million to $104.2 million in FY 2011 due to the FY 2011 bond financing plan and schedule of construction costs for these funds in FY 2011.

The debt service funds decreased $137.1 million in FY 2011 to $62.8 million. The decrease is due in part to the maturity schedule of outstanding debt along with restructuring and funding activities associated with the Spring 2011 Bond Sale.

Deferred Charges increased $32.5 million in FY 2011 from $821.7 million to $854.2 million. Components of this increase were changes in Costs in Excess of Billings related to the net effect of payment of current maturities and refunding activity related to available debt of $24.9 million. There was also a slight decrease to unamortized debt expense of $1.6 million due to refunding activity. Relicensing activities of $6.0 million for Columbia accounted for the remainder of the change. Columbia was issued a standard 40-year operating license by the Nuclear Regulatory Commission (NRC) in 1983. On January 19, 2010 Energy Northwest submitted an application to the NRC to renew the license for an additional 20 years, thus continuing operations to 2043. The estimated duration of the license renewal process is 20 to 24 months from acceptance of the application; notice is expected in FY 2013. The accumulated decommissioning and site restoration accrued costs related to Columbia will be affected by any relicensing decisions. These 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 12 to the Financial Statements.)

Current Liabilities decreased $131.1 million in FY 2011 to $87.5 million mostly due to the decrease of $140.7 million in current maturities of long-term debt. This decrease was offset by an increase of $9.6 million in year-end obligations related to the extended R-20 activity.

Restricted Liabilities (Special Funds and Debt Service) increased $30.0 million in FY 2011 to $225.6 million due to bond activity.

Long-Term Debt increased $176.1 million in FY 2011 from $2.40 billion to $2.57 billion due to the FY 2011 refunding issuance. Current maturing debt is not included. In FY 2011, new debt was issued for various Columbia operational and construction projects, the extension of some maturing debt, the early redemption of certain callable maturities, and to pay for a portion of the costs of issuing debt.

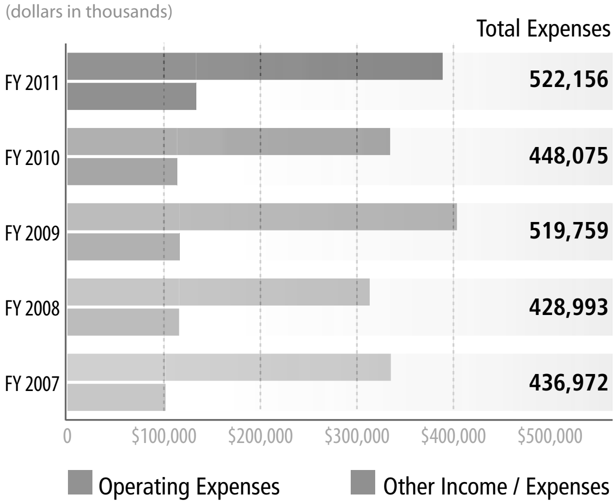
Other long-term liabilities increased $1.6 million in FY 2011 to $14.0 million related to nuclear fuel cask activity.

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 increased $54.5 million from FY 2010 to $388.9 million from the effects of the planned R-20 78 day outage activity combined with the extension of the outage through fiscal year end. Operations and Maintenance costs increased $74.6 million, which is attributable to the increased maintenance projects performed during R-20. The increase to Operations and Maintenance costs was offset by lower nuclear fee costs of $5.5 million and generation taxes of $0.5 million which are a direct result of decreased generation. Administrative and general expenses decreased $5.2 million; drivers for this change were a decrease of $8.7 million in litigation costs related to the spent fuel project (see note 13 for further discussion), offset by increases of $3.5 million for staffing requirements, related benefit programs and regulatory requirements.

Columbia Generating Station
TOTAL OPERATING COSTS
(dollars in thousands)



Other Income and Expenses increased $19.6 million from FY 2010 to $133.3 million net expenses in FY 2011. Expenses associated with the retirement of the condenser contributed to $25.0 million of the increase. The loss on the condenser was offset by gains of $6.4 million for enrichment services and loaned fuel. The remaining net changes in other income and expenses of $3.0 million resulted from increased cost due to bond activity of $4.4 million, offset by increased investment income of $0.2 million due to market condition and increases to non-generation related revenue of $3.2 million.

Columbia's total operating revenue increased from $448.1 million in FY 2010 to $522.2 million in FY 2011. The increase of $74.1 million was due to the originally planned 78 day R-20 activities and the impacts of the extension of the outage through the end of the fiscal year. R-20 was originally budgeted for $153.7 million and 78 days. Actual cost and days through June 30, 2011 were $171.6 million and 85 days. R-20 activities continued through September of FY 2012. Columbia officially synced to the grid on September 27, 2011, signaling the end of R-20.

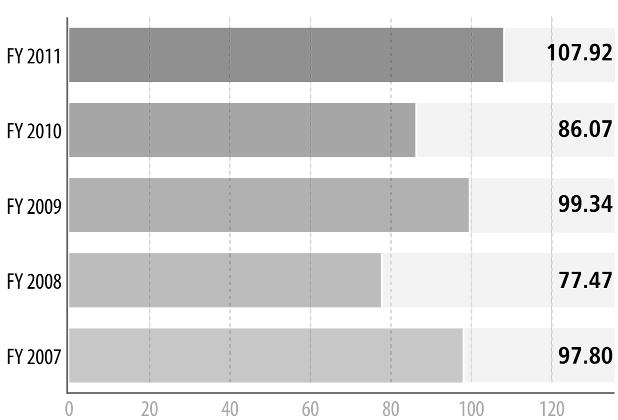
Columbia's insurer, NEIL, paid BPA $3.4 million for settlement of the final payment of the reactor building siding repair which resulted from costs incurred for this and previous fiscal years. Damage was incurred in February 2008. The $3.4 million received in FY 2011 represents the final portion of the $14.0 million dollar total claim that was reimbursable.

Packwood Lake Hydroelectric Project

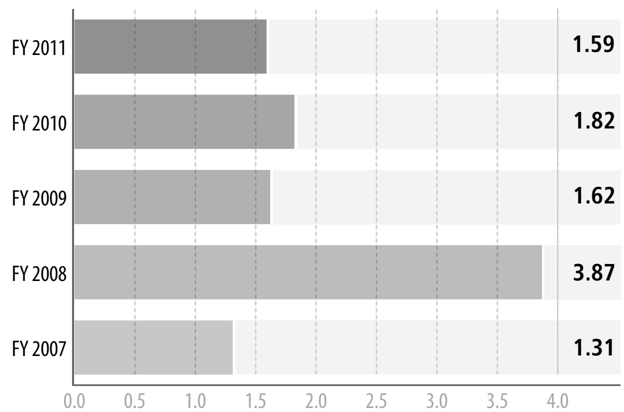
The Packwood Lake Hydroelectric Project (Packwood) is wholly owned and operated by Energy Northwest. Packwood consists of a diversion structure at Packwood Lake and a powerhouse located near the town of Packwood, Wash. The water is carried from the lake to the powerhouse through a five-mile long buried tunnel and drops nearly 1,800 feet in elevation. Packwood produced 107.92 GWh of electricity in FY 2011 versus 86.07 GWh in FY 2010. The 25.4 percent increase in generation can be attributed to increased water availability compared to the previous year. FY 2011 was the 4th highest generation in the last 18 years while FY 2010 was near the 90.5 GWh 46 year average.

Packwood's cost performance is measured by the cost of power indicator. The cost of power for FY 2011 was $1.59 cents/kWh as compared to $1.82 cents/kWh in FY 2010. The cost of power fluctuates year-to-year depending on various factors such as outage, maintenance, generation, and other operating costs. The FY 2011 cost of power decrease of 12.6 percent was a result of increased generation from FY 2010 partially offset by increased costs in FY 2011 due to maintenance and miscellaneous hydro costs.

Packwood Lake Hydroelectric Project
NET GENERATION - GWhrs



Packwood Lake Hydroelectric Project
COST OF POWER - Cents/kWh



Balance Sheet Analysis

Total assets decreased $0.2 million from FY 2010, with the drivers being a decrease to cash due to operations of $0.1 million and a decrease to plant of $0.1 million with $22k related to historical adjustment to accumulated depreciation and net book value of assets (See Note 2 to Financial Statements). The corresponding increases to total liabilities resulted from year end costing recognition. Packwood has incurred $3.7 million in relicensing costs through FY 2011. These costs are shown as Deferred Charges on the Balance Sheet. Packwood has been operating under a 50-year license issued by the Federal Energy Regulatory Commission (FERC), which expired on February 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on February 22, 2008. On March 4, 2010, FERC issued a one-year extension to operate under the original license which is indefinitely extended for continued operations until formal decision is issued by FERC and a new operating license is granted. As of June 30, 2011, Packwood is relicensed under this extended agreement.

Statement of Operations Analysis

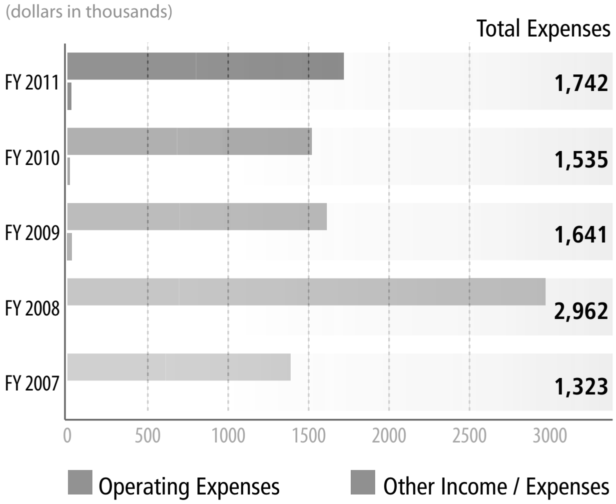
The agreement with Packwood participants obligates them to pay annual costs and to receive excess revenues. (See Note 1 to the Financial Statements.) Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized and no equity is accumulated.

Operating expenses increased $0.2 million from FY 2010 amounts. Most costs remained steady from FY 2010 to FY 2011; the increased costs related to repairs of the turbine runner ($44k), purchases of backup batteries ($48k), and additional project management costs ($175k). Remaining changes in costs were increases to generation tax related to the generation increase ($8k), increases resulting from staffing and related benefits ($10k), and changes to power and depreciation expenses ($2k). Overall increases were offset by lower operating and maintenance costs of $87k.

Packwood is obligated to supply a specified amount of power hourly, known as Priority Firm Energy (PFE). The amount varies monthly based on historical average generation. If the project cannot deliver PFE, replacement power must be purchased on the spot market. Electrical energy from Packwood is currently sold directly to Snohomish PUD which purchases all of the output directly. The power purchase agreement (PPA) provides a predetermined rate for all firm delivery, per the contract schedule and the Mid-Columbia (Mid-C) based rate for any deliveries above firm, or secondary power. Conversely, if there is excess capacity per the PPA with Snohomish PUD, Energy Northwest sells the excess on the open market for additional revenues to be included as part of the PPA with the participants of the project. (See Note 6 to the Financial Statements.)

Other Income and Expenses increased from a net loss of $15k in FY 2010 to a net loss of $23k in FY 2011. The $8k increase in net loss from other income and expenses was due to increased expenses related to the line of credit and lower investment earnings.

Packwood Lake Hydroelectric Project
TOTAL OPERATING COSTS
(dollars in thousands)



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

Long-term debt decreased $176.7 million from $1.799 billion in FY 2010 to $1.622 billion in FY 2011 as a result of maturing debt per schedule. The decrease in long term debt was offset by the $90.5 million increase in the current debt per the debt maturity schedule.

Statement of Operations Analysis

Other Income and Expenses showed a net decrease to expenses of $2.0 million from $86.2 million in FY 2010 to $84.2 million in FY 2011. Investment revenue stayed steady, bond related expenses decreased $2.3 million but were offset by an increase in $0.3 million for plant preservation and decommissioning costs.

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. The debt service related activities remain and are net-billed. (See Note 13 to the Financial Statements.)

Balance Sheet Analysis

Long-term debt decreased $133.4 million from $1.681 billion in FY 2010 to $1.548 billion in FY 2011, as a result of maturing debt per schedule. The decrease in long term debt was offset by the $85.4 million increase in the current debt per the debt maturity schedule. The remaining change of $9.3 million was related to year-end timing of planned expenses and effects of net-billing operations.

Statement of Operations Analysis

Overall expenses decreased $2.0 million from FY 2010 related to bond activity with Investment income steady with previous year levels.

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 lines have been created within the fund: General Services and Facilities, Generation, Professional Services, and Business Unit Support. Each line may have one or more programs that are managed as a unique business activity.

Balance Sheet Analysis

Total assets decreased $0.9 million from $9.5 million in FY 2010 to $8.6 million in FY 2011. Net Plant decreased $0.5 million, due to increases of $0.1 million from Plant activity offset by a decrease of $0.6 million due the historical adjustment made to accumulated depreciation and net book value (See Note 2 to Financial Statements), and $0.1 of accumulated depreciation. Current assets increased $0.5 million due to current funding of operations. The remaining change was due to a decrease in deferred charges of $1.0 million related to power options derivatives (see note 14). Liabilities remained steady between fiscal years. Net Assets decreased $1.0 million from $7.9 million in FY 2010 to $6.9 million in FY 2011 due to the decrease in value of power option derivatives.

Statement of Operations Analysis

Operating Revenues in FY 2011 totaled $12.1 million as compared to FY 2010 revenues of $10.6 million, an increase of $1.5 million. The majority of the increase was in two sectors, Environmental & Information ($0.8 million) and Professional Services ($0.6 million). Generation has a small increase of $0.1 million to account for the remaining change in revenue.

Other Income and Expenses decreased $3.5 million from $4.5 million in net revenues in FY 2010 to net revenue of $1.0 million FY 2011. Major drivers for the overall change from the previous year were a $1.4 million power sales settlement in FY 2010 which did not recur in 2011. In FY 2011 there was a $0.9 million decrease to power sales options (see note 14). These major drivers were offset by a $1.2 million increase in miscellaneous reimbursements.

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 2011 there were no contributions (transfers); in FY 2010, the Business Development Fund received contributions (transfers) of $2.5 million.

Nine Canyon Wind Project

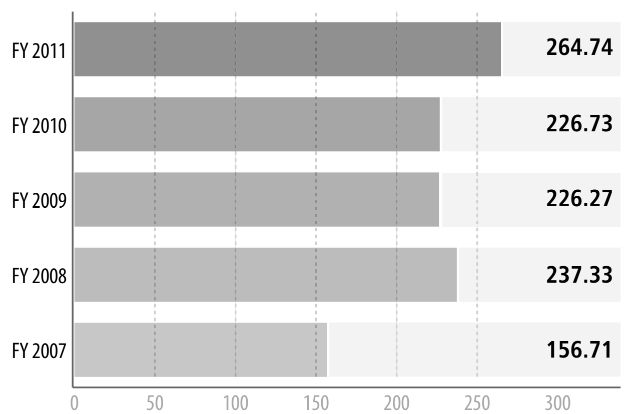
The Nine Canyon Wind Project (Nine Canyon) is wholly owned and operated by Energy Northwest. Nine Canyon is located in the Horse Heaven Hills area southwest of Kennewick, Wash. Electricity generated by Nine Canyon is purchased by Pacific Northwest Public Utility Districts (purchasers). Each of the purchasers of Phase I, Phase II, and Phase III have signed a power purchase agreement which is part of the 2nd Amended and Restated Nine Canyon Wind Project Power Purchase Agreement which now has an end date of 2030. Nine Canyon is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by 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 an aggregate generating capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 12 wind turbines, each with a maximum generating capacity of 1.3 MW, for an aggregate generating capacity of approximately 15.6 MW. Phase III of Nine Canyon, which was declared operational in May 2008, 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, enough energy for approximately 39,000 homes.

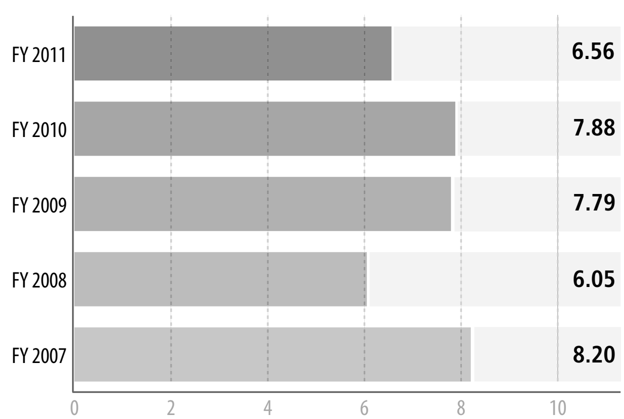
Nine Canyon produced 264.74 GWh of electricity in FY 2011 versus 226.73 GWh in FY 2010. FY 2011 was the highest generation in the history of the project.

Nine Canyon's cost performance is measured by the cost of power indicator. The cost of power for FY 2011 was \$6.56 cents/kWh as compared to \$7.88 cents/kWh in FY 2010. The cost of power fluctuates year to year depending on various factors such as wind totals and unplanned maintenance. The decrease of 16.8 percent cost of power was a result of the record generation coupled with lower operations and maintenance costs due to no major component outages.

Nine Canyon Wind Project
NET GENERATION - GWhrs



Nine Canyon Wind Project
COST OF POWER - Cents/kWh



Balance Sheet Analysis

Total Assets decreased $5.6 million from $133.0 million in FY 2010 to $127.4 million in FY 2011. Major drivers for the change in assets was a decrease of $6.9 million due to plant activity and a small adjustment related to a historical adjustment to accumulated depreciation and net book value of assets (See Note 2 to Financial Statements). The remaining change was an increase to cash of $1.3 million from operations. There was an overall decrease to liabilities of $4.6 million with a decrease to long-term debt of $4.7 million, increases to current debt maturities of $0.3 million, decreases to accrued debt-related interest of $0.1 million and other deferred credits of $0.1 million. The decrease in Net Assets was $1.2 million in FY 2011 as compared to $0.7 million in FY 2010. The decline experienced in previous years is continuing, though the trend is consistent with the rate stabilization approach for Nine Canyon planning. 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 Renewable Energy Production Incentive (REPI) expires. The REPI incentive expires 10 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. Energy Northwest did not receive REPI funding in FY 2011 and is not anticipating future REPI incentives.

Statement of Operations Analysis

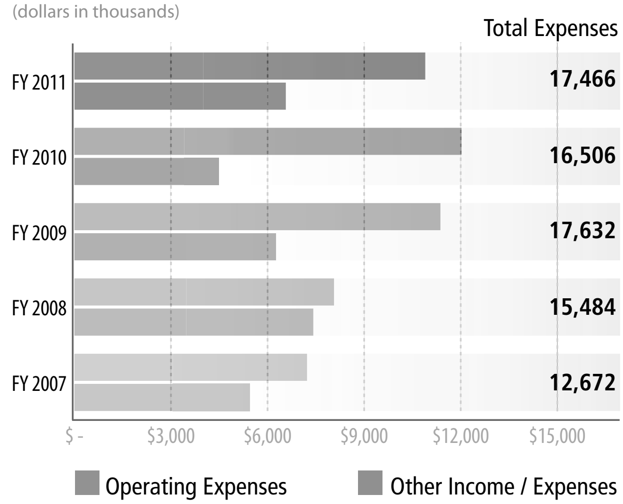
Operating Revenues increased $0.5 million from $15.8 million in FY 2010 to $16.3 million in FY 2011. The project received revenue from the billing of the purchasers at an average rate of $60.69 per MWh for FY 2011 as compared to $66.81 per MWh for FY 2010, which is reflective of the implementation of the revised rate plan in FY 2008 to account for REPI funding shortfalls and costs of operations. The slight increase in operating revenues was due to the planned MWh budgeted rate. Operating costs decreased from $12.0 million in FY 2010 to $10.9 million in FY 2011. Decreased operating costs were due to lower wind technician costs and decreased need for expenditures on main bearings as compared to FY 2010.

Other Income and Expenses increased $2.1 million from $4.5 million in net expenses FY 2010 to $6.6 million in FY 2011. Other revenues decreased due to FY 2010 showing a $2.0 million settlement for bearing replacement on Phase I and II. There was a net cost to Nine Canyon of $0.1 million for BPA scheduling. Investment income associated with bond funds decreased $0.1 million due to market conditions with lower bond related expenses of $0.2 accounting for the remainder of other revenues and expenses. Net losses of $1.2 million for FY 2011 were incurred and are consistent with the expectations of a gradual revenue recovery of operating costs. A declining net asset balance is expected in future years until bond principal payments exceed annual depreciation requirements.

In previous years Energy Northwest has accrued, as income (contribution) from DOE, REPI payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI bill. REPI was created to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. Energy Northwest had no REPI activity for FY 2011.

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 did not receive funding for FY 2010. The payment stream from Nine Canyon participants and the REPI receipts were projected to cover the total costs over the purchase agreement. Continued 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, 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 cash requirements of debt repayment and the cost of operations. Phase III started with an initial planning rate of $49.82 per MWh which increased at 3 percent per year for three years. In year six (FY 2013) 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.

Nine Canyon Wind Project
TOTAL OPERATING COSTS
(dollars in thousands)



Internal Service Fund

The Internal Service Fund, 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 1 to Financial Statements.)

Balance Sheet Analysis

Total Assets for FY 2011 increased $18.0 million from $37.6 million in FY 2010 to $55.6 million in FY 2011. The six major items for the change were 1) increases to net plant of $7.4 million, reflecting $9.6 million of an historical adjustment to plant activity and $2.2 million decrease due to period activity, 2) increase of $8.2 million to Cash for anticipated year end check and warrant redemption, 3) an increase in performance fee of $1.0 million for payments from other business units, 4) an increase of $0.9 million to Personal Time Bank investments and cash, 5) an increase of $0.3 million in restricted assets due to maturity schedule and escrow requirements processing schedule, and 6) an increase to operational activities of $0.2 million.

The net increase in Net Assets and Liabilities is due to increases in Accounts Payable and Payroll related liabilities of $9.3 million due to year-end timing, an increase to Sales Tax Payable of $4.0 million due to off-cycle year fuel activity, an increase of $1.9 million in retention payable related to increased public works activity, a $1.7 million increase in due to other business units, and a $0.3 million decrease to bearer bond activity.

Statement of Operations Analysis

Net Revenues for FY 2011 decreased $29k from FY 2010. The decrease was due to increased costs for lease activity of $36k, decrease in investment returns of $9k, and increases to depreciation of $467k offset by increases in revenue due to operations of $484K.

Balance Sheets As of June 30, 2011 (dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2011 Combined Total
ASSETS									
CURRENT ASSETS									
Cash	$ 39,100	$ 861	$ 69	$ 287	$ 1,357	$ 9,671	$ 51,345	$ 13,680	$ 65,025
Available-for-sale investments	13,858	-	3,137	7,560	4,737	-	29,292	23,481	52,773
Accounts and other receivables	802	471	-	-	501	194	1,968	92	2,060
Due from other business units	4,567	16	255	87	699	-	5,624	362	-
Due from other funds	30,669	-	1,038	26,248	-	951	58,906	-	-
Materials and supplies	103,099	-	-	-	-	-	103,099	-	103,099
Prepayments and other	1,645	67	-	-	-	114	1,826	1,149	2,975
TOTAL CURRENT ASSETS	193,740	1,415	4,499	34,182	7,294	10,930	252,060	38,764	225,932
RESTRICTED ASSETS (NOTE 1)									
Special funds									
Cash	1,125	-	150	1,168	-	5	2,448	293	2,741
Available-for-sale investments	102,846	-	3,096	5,608	-	1,549	113,099	2,699	115,798
Accounts and other receivables	194	-	55	72	-	-	321	-	321
Debt service funds									
Cash	42,747	-	97,458	18,545	-	7,831	166,581	-	166,581
Available-for-sale investments	20,101	-	114,877	146,268	-	11,172	292,418	-	292,418
Accounts and other receivables	-	-	-	184	-	-	184	-	184
TOTAL CURRENT RESTRICTED ASSETS	167,013	-	215,636	171,845	-	20,557	575,051	2,992	578,043
NONCURRENT ASSETS									
Utility Plant (Note 2)									
In service	3,594,468	13,625	-	-	2,065	134,447	3,744,605	48,961	3,793,566
Not in service	-	-	25,253	-	-	-	25,253	-	25,253
Construction work in progress	185,801	-	-	-	-	-	185,801	-	185,801
Accumulated depreciation	(2,370,557)	(12,716)	(25,253)	-	(862)	(40,572)	(2,449,960)	(35,091)	(2,485,051)
Net Utility Plant	1,409,712	909	-	-	1,203	93,875	1,505,699	13,870	1,519,569
Nuclear fuel, net of accumulated amortization	266,949	-	-	-	-	-	266,949	-	266,949
TOTAL NONCURRENT ASSETS	1,676,661	909	-	-	1,203	93,875	1,772,648	13,870	1,786,518
DEFERRED CHARGES									
Costs in excess of billings	822,956	-	1,625,119	1,530,596	-	-	3,978,671	-	3,978,671
Unamortized debt expense	12,551	-	5,803	5,994	-	2,019	26,367	-	26,367
Other deferred charges	18,721	3,737	-	-	116	-	22,574	-	22,574
TOTAL DEFERRED CHARGES	854,228	3,737	1,630,922	1,536,590	116	2,019	4,027,612	-	4,027,612
TOTAL ASSETS	$ 2,891,642	$ 6,061	$ 1,851,057	$ 1,742,617	$ 8,613	$ 127,381	$ 6,627,371	$ 55,626	$ 6,618,105

*Project recorded on a liquidation basis
The accompanying notes are an integral part of these combined financial statements

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2011 Combined Total
LIABILITIES AND NET ASSETS									
CURRENT LIABILITIES									
Current maturities of long-term debt	$ 45	$ -	$ 166,030	$ 129,435	$ -	$ 4,260	$ 299,770	$ -	$ 299,770
Accounts payable and accrued expenses	50,991	182	247	172	1,675	506	53,773	44,319	98,092
Due to Participants	36,488	868	-	-	-	-	37,356	-	37,356
Due to other business units	-	-	-	-	-	362	362	5,624	-
TOTAL CURRENT LIABILITIES	87,524	1,050	166,277	129,607	1,675	5,128	391,261	49,943	435,218
LIABILITIES- PAYABLE FROM CURRENT RESTRICTED ASSETS (NOTE 1)									
Special funds									
Accounts payable and accrued expenses	132,111	-	15,839	-	-	1,187	149,137	293	149,430
Due to other funds	30,667	-	301	3,848	-	951	35,767	-	-
Debt service funds									
Accrued interest payable	62,801	-	45,568	39,076	-	3,387	150,832	-	150,832
Due to other funds	2	-	737	22,400	-	-	23,139	-	-
TOTAL CURRENT RESTRICTED LIABILITIES	225,581	-	62,445	65,324	-	5,525	358,875	293	300,262
LONG-TERM DEBT (NOTE 5)									
Revenue bonds payable	2,487,355	-	1,573,805	1,495,480	-	136,505	5,693,145	-	5,693,145
Unamortized (discount)/ premium on bonds - net	92,655	-	55,641	53,430	-	4,155	205,881	-	205,881
Unamortized loss on bond refundings	(15,501)	-	(7,111)	(1,224)	-	-	(23,836)	-	(23,836)
TOTAL LONG-TERM DEBT	2,564,509	-	1,622,335	1,547,686	-	140,660	5,875,190	-	5,875,190
OTHER LONG-TERM LIABILITIES	14,028	-	-	-	-	-	14,028	-	14,028
DEFERRED CREDITS									
Advances from Members and others	-	5,011	-	-	-	-	5,011	-	5,011
Advances from Members and others	-	-	-	-	-	-	-	651	651
Other deferred credits	-	-	-	-	-	153	153	5	158
TOTAL DEFERRED CREDITS	-	5,011	-	-	-	153	5,164	656	5,820
NET ASSETS									
Invested in capital assets, net of related debt	-	-	-	-	1,203	(49,026)	(47,823)	13,870	(33,953)
Restricted, net	-	-	-	-	-	14,879	14,879	2,699	17,578
Unrestricted, net	-	-	-	-	5,735	10,062	15,797	(11,835)	3,962
NET ASSETS	-	-	-	-	6,938	(24,085)	(17,147)	4,734	(12,413)
TOTAL LIABILITIES	2,891,642	6,061	1,851,057	1,742,617	1,675	151,466	6,644,518	50,892	6,630,518
TOTAL LIABILITIES AND NET ASSETS	$ 2,891,642	$ 6,061	$ 1,851,057	$ 1,742,617	$ 8,613	$ 127,381	$ 6,627,371	$ 55,626	$ 6,618,105

*Project recorded on a liquidation basis
The accompanying notes are an integral part of these combined financial statements

Statements Of Revenues, Expenses, And Changes In Net Assets

As of June 30, 2011 (dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2011 Combined Total
OPERATING REVENUES	$ 522,156	$ 1,742	$ -	$ -	$ 12,144	$ 16,250	$ 552,292	$ -	$ 552,292
OPERATING EXPENSES									
Nuclear fuel	30,772	-	-	-	-	-	30,772	-	30,772
Spent fuel disposal fee	6,845	-	-	-	-	-	6,845	-	6,845
Decommissioning	7,090	-	-	-	-	80	7,170	-	7,170
Depreciation and amortization	66,636	59	-	-	196	6,790	73,681	-	73,681
Operations and maintenance	247,008	1,462	-	-	13,331	3,938	265,739	-	265,739
Other power supply expense	-	17	-	-	-	-	17	-	17
Administrative & general	27,358	156	-	-	-	34	27,548	-	27,548
Generation tax	3,166	25	-	-	-	57	3,248	-	3,248
TOTAL OPERATING EXPENSES	388,875	1,719	-	-	13,527	10,899	415,020	-	415,020
NET OPERATING REVENUES	133,281	23	-	-	(1,383)	5,351	137,272	-	137,272
OTHER INCOME AND EXPENSE									
Other	(14,210)	-	84,228	76,356	1,939	(129)	148,184	71,909	148,269
Investment income	721	3	72	70	(943)	81	4	38	4
Interest expense and discount amortization	(119,792)	(26)	(82,094)	(76,064)	-	(6,519)	(284,495)	-	(284,495)
Plant preservation and termination costs	-	-	(1,656)	(362)	-	-	(2,018)	-	(2,018)
Depreciation and amortization	-	-	(6)	-	-	-	(6)	(2,268)	(6)
Decommissioning	-	-	(544)	-	-	-	(544)	-	(544)
Services to other business units	-	-	-	-	-	-	-	(69,594)	-
TOTAL OTHER INCOME AND EXPENSE	(133,281)	(23)	-	-	996	(6,567)	(138,875)	85	(138,790)
Changes in Net Assets	-	-	-	-	(387)	(1,216)	(1,603)	85	(1,518)
(DISTRIBUTION)/CONTRIBUTION	-	-	-	-	-	-	-	1,000	1,000
TOTAL NET ASSETS, BEGINNING OF YEAR	-	-	-	-	7,325	(22,869)	(15,544)	3,649	(11,895)
TOTAL NET ASSETS, END OF YEAR	$ -	$ -	$ -	$ -	$ 6,938	$ (24,085)	$ (17,147)	$ 4,734	$ (12,413)

*Project recorded on a liquidation basis
The accompanying notes are an integral part of these combined financial statements

Statements Of Cash Flows

As of June 30, 2011 (dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2011 Combined Total
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES								
Operating revenue receipts	$ 464,563	$ 1,569	$ -	$ -	$ 8,965	$ 16,685	$ -	$ 491,782
Cash payments for operating expenses	(267,790)	(1,721)	-	-	(8,728)	(4,619)	-	(282,858)
Other revenue receipts	-	-	259,036	207,163	-	130	-	466,329
Cash payments for preservation, termination expense	-	-	(1,006)	(256)	-	-	-	(1,262)
Cash payments for services	-	-	-	-	-	-	11,243	11,243
Net cash provided/(used) by operating and other activities	196,773	(152)	258,030	206,907	237	12,196	11,243	685,234
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	532,565	-	-	106,667	-	-	-	639,232
Deposit to Debt Service Fund	(347,355)	-	-	-	-	-	-	(347,355)
Payment for bond issuance and financing costs	(3,224)	-	(203)	(107,297)	(1)	(32)	-	(110,757)
Payment for capital items	(109,930)	23	-	-	311	78	(1,421)	(110,939)
Receipts from sales of plant assets	-	-	3	-	-	-	-	3
Nuclear fuel acquisitions	(93,890)	-	-	-	-	-	-	(93,890)
Interest paid on revenue bonds	(123,727)	-	(92,525)	(107,645)	-	(6,868)	-	(330,765)
Principal paid on revenue bond maturities	(140,790)	(4)	(75,505)	(10,167)	-	(3,965)	-	(230,431)
Net cash provided/(used) by capital and related financing activities	(286,351)	19	(168,230)	(118,442)	310	(10,787)	(1,421)	(584,902)
CASH FLOWS FROM NON-CAPITAL FINANCE ACTIVITIES	-	-	-	-	-	-	-	-
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(409,128)	(644)	(405,856)	(371,135)	(10,046)	(29,975)	(27,494)	(1,254,278)
Sales of investment securities	553,860	644	406,182	297,175	9,470	30,062	25,566	1,322,959
Interest on investments	903	3	72	(4)	9	91	349	1,423
Net cash provided/(used) by investing activities	145,635	3	398	(73,964)	(567)	178	(1,579)	70,104
NET INCREASE (DECREASE) IN CASH	56,057	(130)	90,198	14,501	(20)	1,587	8,243	170,436
CASH AT JUNE 30, 2010	26,915	991	7,479	5,499	1,377	15,920	5,730	63,911
CASH AT JUNE 30, 2011	$ 82,972	$ 861	$ 97,677	$ 20,000	$ 1,357	$ 17,507	$ 13,973	$ 234,347

*Project recorded on a liquidation basis
The accompanying notes are an integral part of these combined financial statements

Statements Of Cash Flows (Cont'd)

As of June 30, 2011 (dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No.1*	Nuclear Project No.3*	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2010 Combined Total
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net operating revenues	$ 133,281	$ 23	$ -	$ -	$ (1,383)	$ 5,351	$ -	$ 137,272
Adjustments to reconcile net operating revenues to cash provided by operating activities:								
Depreciation and amortization	95,105	48	-	-	108	6,770	-	102,031
Decommissioning	7,090	-	-	-	-	33	-	7,123
Other	(13,745)	26	-	-	813	(97)	-	(13,003)
Change in operating assets and liabilities:							-	
Deferred charges/costs in excess of billings	(57,192)	(48)	-	-	-	-	-	(57,240)
Accounts receivable	146	(49)	-	-	590	(57)	-	630
Materials and supplies	1,951	-	-	-	-	-	-	1,951
Prepaid and other assets	(395)	-	-	-	-	6	-	(389)
Due from/to other business units, funds and Participants	(1,306)	(14)	-	-	-	391	-	(929)
Accounts payable	31,838	(138)	-	-	109	(201)	-	31,608
Other revenue receipts	-	-	259,036	207,163	-	-	-	466,199
Cash payments for preservation, termination expense	-	-	(1,006)	(256)	-	-	-	(1,262)
Cash payments for services	-	-	-	-	-	-	11,243	11,243
Net cash provided (used) by operating and other activities	$ 196,773	$ (152)	$ 258,030	$ 206,907	$ 237	$ 12,196	$ 11,243	$ 685,234

*Project recorded on a liquidation basis
The accompanying notes are an integral part of these combined financial statements

Energy Northwest Notes To Financial Statements

Note 1 - Summary Of Operations and Significant Accounting Policies

Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, was organized in 1957 to finance, acquire, construct and operate facilities for the generation and transmission of electric power.

Membership consists of 23 public utility districts and five municipalities. All members own and operate electric systems within the State of Washington.

Energy Northwest is exempt from federal income tax and has no taxing authority.

Energy Northwest maintains seven business units. Each 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 public 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 6).

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. On January 19, 2010 Energy Northwest submitted an application to the NRC to renew the license for an additional 20 years, thus continuing operations until 2043. The estimated duration of the license renewal process is 20 to 24 months from acceptance of the application. Costs to date for Columbia relicensing are $18.7 million and are shown as deferred charges in the balance sheet.

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5-MWe generating plant completed in 1964. Packwood has been operating under a 50-year license issued by the Federal Energy Regulatory Commission (FERC), which expired on Feb. 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on Feb. 22, 2008. On March 4, 2010, FERC issued a one-year extension, or until the issuance of a new license for the project or other disposition under the Federal Power Act, whichever comes first. FERC is awaiting issuance of the National Oceanic and Atmospheric Administration's (NOAA) Biological Opinion (BO), after which FERC will complete the final license renewal documentation for Packwood. Costs incurred to date for relicensing are $3.7 million.

The electric power produced by Packwood is sold to 12 project participant utilities which pay the costs of Packwood. 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 bond resolution. The participants also share Packwood revenue.

In October 2008, Packwood entered into a new Power Sales Agreement with Snohomish PUD to purchase the entire project output (see Note 6). This contract was extended in the fall of 2010 and will continue until the fall of 2011. The Packwood participants will then assume the responsibility to purchase their respective shares in the fall of 2011, or they can re-assign their shares to other participants.

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. 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 13)

The Business Development Fund was established in April 1997 to pursue and develop new energy related business opportunities. There are four main business lines associated with this business unit: General Services and Facilities, Generation, Professional Services, and Business Unit Support.

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 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 adding an additional 14 wind turbines to the Nine Canyon Wind Project and adding an aggregate capacity of 32.2 MWe. The total number of turbines at Nine Canyon is 63 and the total capacity 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.

Energy Northwest's fiscal year begins on July 1 and ends on June 30. In preparing these financial statements, the Company has evaluated events and transactions for potential recognition or disclosure through November 30, 2011, the date the financial statements were issued.

The following is a summary of the significant accounting policies:

a) **Basis of Accounting and Presentation:**
The accounting policies of Energy Northwest conform to GAAP applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. Energy Northwest has applied all applicable GASB pronouncements and elected to apply Financial Accounting Standards Board (FASB) standards except for those conflicting with or in contradiction to GASB pronouncements. The accounting and reporting policies of Energy Northwest are regulated by the Washington State Auditor's Office and are based on the Uniform System of Accounts prescribed for public utilities and licensees by FERC. Energy Northwest uses the full accrual basis of accounting where revenues are recognized when earned and expenses are recognized when incurred. Revenues and expenses related to Energy Northwest's operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be other income and expenses. Separate funds and book of accounts 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. (See Note 5)

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 as Current Liabilities–Due to other business units, or as 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 2011 Combined Total includes eliminations for transactions between business units as required in GASB Statement No. 34, "Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments."

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 standards, 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 ASC 860, "Transfers and Servicing." As such, the guidance under GASB No. 7 and No. 23 is followed. Such guidance governs the accounting for bond defeasances and refundings.

b) **Utility Plant and Depreciation:**

Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs.

Property, plant, and equipment are depreciated using the straight-line method over the following estimated useful lives:

Buildings and Improvements	20 - 60 years
Generation Plant	40 years
Transportation Equipment	6 - 9 years
General Plant and Equipment	3 - 15 years

Group rates are used for assets and, accordingly, no gain or loss is recorded on the disposition of an asset unless it represents a major retirement. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation.

The utility plant and net assets of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in FY 1995 and 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.

c) **Allowance for Funds Used During Construction (AFUDC):**

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. However, if estimated costs are more than inconsequential, an adjustment is made to allocate capitalized interest to the appropriate plant account. Interest costs capitalized for FY 2011 totaled $0.6 million and related to Columbia.

d) Nuclear Fuel:

Energy Northwest has various agreements for uranium concentrates, conversion, and enrichment to provide for short-term enriched uranium product and long-term enrichment services. These contracts do not obligate Energy Northwest to purchase fuel components in excess of the requirements of operations. 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 assemblies in the reactor used in the production of energy and in the fuel pool for less than six months per FERC guidelines) is $53.5 million as of June 30, 2011. Fees for disposal of fuel in the reactor are expensed as part of the fuel cost.

Energy Northwest has a contract with the U.S. Department of Energy (DOE) that requires the DOE to accept title and dispose of spent nuclear fuel (reference to the term "spent fuel" is due to DOE contract and current court proceedings. "Used fuel" is the preferred term by Energy Northwest). Although the courts have ruled that DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. Energy Northwest was awarded Final Judgment and received damages in the amount of $48,702,551 (See Note 13).

The current period operating expense for Columbia includes a $6.8 million charge from DOE for future spent 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. No casks were issued from the cask inventory account in FY 2011. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refuelings. Current period costs include $29.1 million for nuclear fuel and $1.7 million for dry cask storage costs.

e) Asset Retirement Obligation:

Energy Northwest has adopted ASC 410, "Asset Retirement and Environmental Obligations". This standard requires Energy Northwest to recognize the fair value of a liability associated with the retirement of a long-lived asset, such as: Columbia Generating Station, Nuclear Project No. 1, and Nine Canyon, in the period in which it is incurred. (See Note 11)

f) 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. (See Note 12)

g) Derivative Instruments:

In June, 2008, GASB issued Statement No. 53, "Accounting and Financial Reporting for Derivative Instruments." Statement No. 53 provides a comprehensive framework for the measurement, recognition and disclosure of derivative instrument transactions for the purpose of enhancing the usefulness and comparability of derivative instrument information reported by state and local governments. (See Note 14)

h) **Restricted Assets:**

In accordance with bond resolutions, related agreements and laws, separate restricted accounts have been established. These assets are restricted for specific uses including debt service, construction, capital additions and fuel purchases, extraordinary operation and maintenance costs, termination, decommissioning, operating reserves, financing, long-term disability, and workers' compensation claims. They are classified as current or non-current assets as appropriate.

i) **Cash and Investments:**

For purposes of the Statement of Cash Flows, cash includes unrestricted and restricted cash balances and each business unit maintains its cash and investments. Short-term highly liquid investments are not considered to be cash equivalents, but are classified as available-for-sale investments and are stated at fair value with unrealized gains and losses reported in investment income. (See Note 3) 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. Safe keeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest business units.

j) **Accounts Receivable:**

The percentage of sales method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a yearly basis. Accounts receivable specific to each business unit are recorded in the residing business unit.

k) **Other Receivables:**

Other receivables include amounts related to the Internal Service Fund from miscellaneous outstanding receivables from other business units which have not yet been collected. The amounts due to each business unit are reflected in the Due To/From other business unit's account. Other receivables specific to each business unit are recorded in the residing business unit.

l) **Materials and Supplies:**

Materials and supplies are valued at cost using the weighted average cost method.

m) **Long-Term Liabilities:**

These consist of obligations related to bonds payable and the associated premiums/discounts and gains/losses. Other noncurrent liabilities for Columbia relate to the dry cask storage activity.

Long-Term Liability activity for the year ended June 30, 2011 was as follows:

Long-Term Liabilities (dollars in thousands)

	Beginning Balance	Increases	Decreases	Ending Balance
Columbia Generating Station				
Revenue bonds payable	$ 2,327,455	$ 501,570	$ 341,670	$ 2,487,355
Unamortized (discount)/premium on bonds - net	78,202	30,637	16,184	92,655
Unamortized gain/(loss) on bond refundings	(8,232)	(12,005)	4,736	(15,501)
Other noncurrent liabilities	12,373	1,655		14,028
Current portion	140,790		140,745	45
	$ 2,550,588	$ 521,857	$ 503,335	$ 2,578,582
Nuclear Project No.1				
Revenue bonds payable	$ 1,739,835	$ -	$ 166,030	$ 1,573,805
Unamortized (discount)/premium on bonds - net	71,488	30	15,877	55,641
Unamortized gain/(loss) on bond refundings	(12,292)	(237)	5,418	(7,111)
Current portion	75,505	166,030	75,505	166,030
	$ 1,874,536	$ 165,823	$ 262,830	$ 1,788,365
Nuclear Project No.3				
Revenue bonds payable	$ 1,637,715	$ 92,285	$ 234,520	$ 1,495,480
Unamortized (discount)/premium on bonds - net	47,646	12,797	7,013	53,430
Unamortized gain/(loss) on bond refundings	(4,235)	(948)	3,959	(1,224)
Current portion	44,050	129,435	44,050	129,435
	$ 1,725,176	$ 233,569	$ 289,542	$ 1,677,121
Nine Canyon Wind Project				
Revenue bonds payable	$ 140,765		$ 4,260	$ 136,505
Unamortized (discount)/premium on bonds - net	4,633		478	4,155
Current portion	3,965	4,260	3,965	4,260
	$ 149,363	$ 4,260	$ 8,703	$ 144,920

n) **Debt Premium, Discount and Expense:**
Original issue and reacquired bond premiums, discounts and expenses relating to the bonds are amortized over the terms of the respective bond issues using the bonds outstanding method which approximates the effective interest method. In accordance with GASB Statement No. 23, "Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities," 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.

o) Revenue Recognition:

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 accumulated. The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (deferred credit) or as costs in excess of billings (deferred debit), as appropriate. Such amounts will be settled during future operating periods. (See Note 6)

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 loss and included in Net Assets for each period.

p) Capital Contribution:

Renewable Energy Performance Incentive (REPI) payments enable Nine Canyon to receive funds based on generation as it applies to the REPI bill. 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 did not record a receivable for FY 2011 REPI funding as no funds are anticipated to be disbursed to Energy Northwest under this program. The payment stream from Nine Canyon participants and the anticipated 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 schedule for the Nine Canyon participants covers total project costs occurring in FY 2011 and projections out to the 2030 proposed end date.

q) Compensated Absences:

Employees earn leave in accordance with length of service. Energy Northwest accrues the cost of personal leave in the year when earned. The liability for unpaid leave benefits and related payroll taxes was $19.9 million at June 30, 2011 and is recorded as a current liability.

r) Use of Estimates:

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.

Note 2 - Utility Plant

Utility plant activity for the year ended June 30, 2011 was as follows:

Utility Plant Activity (dollars in thousands)

	Beginning Balance	Increases	Decreases	Ending Balance
Columbia Generating Station				
Generation	3,588,450	59,536	(85,987)	3,561,999
Decommissioning	32,469	-	-	32,469
Construction Work-in-Progress	146,030	99,046	(59,275)	185,801
Accumulated Depreciation and Decommissioning	(2,391,614)	(81,818)	102,875	(2,370,557)
Utility Plant, net	1,375,335	76,764	(42,387)	1,409,712
Packwood Lake Hydroelectric Project				
Generation	13,647	-	(22)	13,625
Accumulated Depreciation	(12,668)	(48)	-	(12,716)
Utility Plant, net	$ 979	$ (48)	$ (22)	$ 909
Business Development				
General	2,399	255	(589)	2,065
Construction Work-in-Progress	-	-	-	-
Accumulated Depreciation	(742)	(120)	-	(862)
Utility Plant, net	1,657	135	(589)	1,203
Nine Canyon Wind Project				
Generation	133,666	265	(345)	133,586
Decommissioning	861	-	-	861
Construction Work-in-Progress	-	213	(213)	-
Accumulated Depreciation and Decommissioning	(33,771)	(6,801)	-	(40,572)
Utility Plant, net	100,756	(6,323)	(558)	93,875
Internal Service Fund				
General	46,914	2,481	(434)	48,961
Construction Work-in-Progress	591	-	(591)	-
Accumulated Depreciation	(40,999)	(2,293)	8,201	(35,091)
Utility Plant, net	6,506	188	7,176	13,870

* Does not include Nuclear Fuel Amount of $267 million, net of amortization.

Reclassifications took place in FY 2011 for various plant and accumulated depreciation accounts. Corrections were a result of legacy adjustments made in the asset records that tracked historical changes. Changes reported for each business unit were:

	Plant	Accumulated Depreciation
Columbia Generating Station	(1,336)	34,273
Packwood Lake Hydroelectric Project	(22)	-
Business Development	(589)	(13)
Nine Canyon Wind Project	-	(2)
Internal Service Fund	1,870	7,741
Total Legacy Adjustments	(77)	41,999

Note 3 - Deposits And Investments

As of June 30, 2011, Energy Northwest had the following unrealized gains and losses:

Available-For-Sale-Investments (dollars in thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia Generating Station	$ 136,627	$ 178	$ -	$ 136,805
Packwood Lake Hydroelectric Project	-	-	-	-
Nuclear Project No. 1	121,110	-	-	121,110
Nuclear Project No. 3	159,434	2	-	159,436
Business Development Fund	4,736	1	-	4,737
Internal Service Fund	26,132	52	(4)	26,180
Nine Canyon Wind Project	12,718	4	(1)	12,721

(1) All investments are in U.S. Government backed securities including U.S. Government Agencies and Treasury Bills.
(2) The majority of investments have maturities of less than 1 year. Approximately $21.56 million have a maturity beyond 1 year with the longest maturity being March 8th, 2013.

Interest rate risk: In accordance with its investment policy, Energy Northwest manages its exposure to declines in fair values by limiting investments to those with maturities designated in specific bond resolutions.

Credit risk: Energy Northwest's investment policy restricts investments to debt securities and obligations of the U.S. Treasury, U.S. Government agencies Federal National Mortgage Association and the Federal Home Loan Banks, certificates of deposit and other evidences of deposit at financial institutions qualified by the Washington Public Deposit Protection Commission (PDPC), and general obligation debt of state and local governments and public authorities recognized with one of the three highest credit ratings (AAA, AA+, AA, or equivalent). This investment policy is more restrictive than the state law.

Concentration of credit risk: Energy Northwest investment policy does not specifically address concentration of credit risk. An individual authorized security or obligation can receive up to 100 percent of the authorized investment amount; there are no individual concentration limits.

Custodial credit risk, Deposits: For a deposit, this is the risk that in the event of bank failure, Energy Northwest's deposits may not be returned to it. Energy Northwest's interest bearing accounts and certificates of deposits are covered up to $250,000 by Federal Depository Insurance Corporation (FDIC) while non-interest bearing deposits are entirely covered by FDIC and if necessary, all interest and non-interest bearing deposits are covered by collateral held in multiple financial institution collateral pool administered by the Washington State Treasurer's Local Government Investment Pool (LGIP). Under state law, public depositories under the PDPC may be assessed on a prorated basis if the pool's collateral is insufficient to cover a loss. As a result, deposits covered by collateral held in the multiple financial institution collateral pool are considered to be insured. State law requires deposits may only be made with institutions that are approved by the PDPC.

Note 4 – Others Deferred Charges And Deferred Credits

Other deferred charges of $18.7 million and $3.7 million relate to the Columbia and Packwood relicensing effort, respectively. Business Development deferred charge of $0.1 million relates to derivative power options. (See Note 14) Other deferred credits of $0.2 million consist of turbine elevator purchases for Nine Canyon that will be completed in FY 2013.

Note 5 - 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 (2006 Bonds).

During the year ended June 30, 2011, Energy Northwest issued, for Columbia, the Series 2010-D, 2011-B, and 2011-C Bonds. The Series 2011-A Bonds were issued for Nuclear Project 3 and Columbia. The Series 2010-D, 2011-A, 2011-B, and 2011-C Bonds issued for Nuclear Project No. 3 and Columbia are fixed rate bonds with a weighted average coupon interest rate ranging from 3.55 percent to 5.70 percent. These transactions resulted in a net loss for accounting purposes of $11.71 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.

The Series 2010-D Bonds issued for Columbia are taxable fixed-rate Build America Bonds to finance costs of acquiring fuel and to finance a portion of the costs planned to be incurred during fiscal years 2011, 2012 and 2013 for certain capital improvements.

The Series 2011-A Bonds issued for Nuclear Project No. 3 and Columbia are tax exempt fixed-rate bonds that refunded certain Electric Revenue Bonds.

The Series 2011-B Bonds issued for Columbia are taxable fixed-rate bonds that refunded certain Electric Revenue Bonds and are to finance a portion of the cost of certain capital improvements.

The Series 2011-C Bonds issued for Columbia are taxable fixed-rate bonds to finance costs of operating Columbia.

The Bond Proceeds, Weighted Average Coupon Interest Rates, Net Accounting Loss, and Total Defeased Bonds for 2010-D, 2011A, 2011B, and 2011-C are presented in the following tables:

Bond Proceeds (dollars in millions)

	2010D	2011A	2011B	2011C	Total
CGS	$ 155.81	$ 341.84	$ 29.92	$ 4.60	$ 532.17
Project 3	-	105.08	-	-	105.08
Total	$ 155.81	$ 446.92	$ 29.92	$ 4.60	$ 637.25

Weighted Average Coupon Interest Rate for Refunded Bonds (dollars in millions)

	2011A	2011B
Total	5.38%	5.23%

Weighted Average Coupon Interest Rate for New Bonds (dollars in millions)

	2010D	2011A	2011B	2011C
Total	5.70%	4.91%	4.92%	3.55%

Net Accounting Loss (Gain) ($ in millions)

	2010D	2011A	2011B	2011C	Total
CGS	$ -	$ (4.72)	$ (6.27)	$ -	$ (10.99)
Project 3	-	(0.72)	-	-	(0.72)
Total	$ -	$ (5.44)	$ (6.27)	$ -	$ (11.71)

Total Defeased (dollars in millions)

	2010D	2011A	2011B	2011C	Total
CGS	$ -	$ 343.95	$ 4.37	$ -	$ 348.32
Project 3	-	105.10	-	-	105.10
Total	$ -	$ 449.05	$ 4.37	$ -	$ 453.42

Energy Northwest did not issue or refund any bonds associated with Packwood or Nine Canyon for FY 2011.

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 2011 defeasements, $33.6 million, $9.5 million, and $88.0 million of defeased bonds were not called or had not matured at June 30, 2011, for Nuclear Projects Nos. 1 and 3, and Columbia respectively.

Outstanding Long-Term Debt As Of June 30, 2011 (dollars In thousands)

Outstanding principal on revenue and refunding bonds for the various business units as of June 30, 2011, and future debt service requirements for these bonds are presented in the following tables:

Columbia Revenue and Refunding Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1992A	6.30	7-1-2012	$ 50,000
1994A	5.40	7-1-2012	100,200
2002A	5.20-5.75	7-1-17/2018	157,260
2002B	5.35-6.00	7-1-2018	63,140
2003A	5.50	7-1-12/2015	103,845
2003F	5.00-5.25	7-1-12/2018	27,015
2004A	5.25	7-1-17/2018	129,260
2004B	5.50	7-1-2013	12,715
2004C	5.25	7-1-12/2018	17,230
2005A	5.00	7-1-15/2018	114,985
2005C	4.52-4.74	7-1-12/2015	55,945
2006A	5.00	7-1-20/2024	434,210
2006B	5.23	7-1-2011	45
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	5.95	7-1-20/2021	12,025
2008C	5.00-5.25	7-1-21/2024	37,240
2008D	5.00	7-1-2012	74,950
2009A	3.00-5.00	7-1-14/2018	116,425
2009B	4.59-6.80	7-1-14/2024	18,515
2009C	4.25-5.00	7-1-20/2024	69,170
2010B	3.75-4.25	7-1-20/2024	16,005
2010C	4.52-5.12	7-1-20/2024	75,770
2010D	5.61-5.71	7-1-23/2024	155,805
2011A	3.00-5.00	7-1-13/2023	311,245
2011B	4.19-5.19	7-1-19/2024	29,920
2011C	3.55	7-1-2019	4,600
		Revenue bonds payable	$ 2,487,400
		Estimated fair value at June 30, 2011	$ 2,746,735 (B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Accounting Standards Codification (ASC) 820 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
2001A	4.50-5.50	7-1-2011	73,010
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
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
2006A	5.00	7-1-11/2017	206,575
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
2008D	5.00	7-1-11/2017	62,085
2009A	3.25-5.00	7-1-14/2015	48,905
2009B	4.59	7-1-2014	515
2010A	2.00-5.00	7-1-11/2017	71,150
2010B	2.00	7-1-2011	815
		Revenue bonds payable	$ 1,739,835
		Estimated fair value at June 30, 2011	$ 1,920,469 (B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Accounting Standards Codification (ASC) 820 and does not purport to represent the amounts at which these obligations would be settled.

Nuclear Project No.3 Refunding Revenue Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1989A	(A)	7-1-11/2014	$ 6,065
1989B	(A)	7-1-11/2014	18,719
	7.125	7-1-2016	76,145
			94,864
1993C	(A)	7-1-13/2018	23,963
2001A	5.50	7-1-2011	34,190
2002B	6.00	7-01-2016	75,360
2003A	5.50	7-1-11/2017	241,915
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
2006A	5.00	7-1-16/2018	39,445
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
2008D	5.00	7-1-11/2017	50,615
2009A	5.00-5.25	7-1-14/2018	116,055
2009B	4.59	7-1-2014	970
2010A	5.00	7-1-16/2018	279,980
2010B	5.00	7-1-2016	29,865
2011A	4.00-5.00	7-1-2018	92,285
		Compound interest bonds accretion	163,663
		Revenue bonds payable	$ 1,624,915
		Estimated fair value at June 30, 2011	$ 1,806,562 (B)

(A) Compound Interest Bonds
(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Accounting Standards Codification (ASC) 820 and does not purport to represent the amounts at which these obligations would be settled.

Nine Canyon Wind Project Revenue and Refunding Bonds

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
2003	3.75-5.00	7-1-11/2023	16,680
2005	4.50-5.00	7-1-11/2023	54,755
2006	4.50-5.00	7-1-11/2030	69,330
		Revenue bonds payable	$ 140,765
		Estimated fair value at June 30, 2010	$ 146,424 (B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Accounting Standards Codification (ASC) 820 and does not purport to represent the amounts at which these obligations would be settled.

Total bonds payable	$ 5,992,915
Estimated fair value at June 30, 2011	$ 6,620,190

Debt Service Requirements As Of June 30, 2011 (Dollars In Thousands)

Columbia Generating Station

Fiscal Year	Principal	Interest	Total
6/30/2011 Balance*	$ 45	$ 62,801	$ 62,846
2012	266,810	127,605	394,415
2013	40,785	113,153	153,938
2014	83,410	111,201	194,611
2015-2017	418,545	295,122	713,667
2018-2022	1,056,405	313,167	1,369,572
2023-2024	621,400	50,201	671,601
	$ 2,487,400	$ 1,073,250	$ 3,560,650

* Principal and Interest due July 1, 2011.

Nuclear Project No. 1

Fiscal Year	Principal	Interest	Total
6/30/2011 Balance*	$ 166,030	$ 45,568	$ 211,598
2012	56,030	82,769	138,799
2013	276,250	80,079	356,329
2014	368,040	65,788	433,828
2015	191,970	46,787	238,757
2016	326,980	37,197	364,177
2017	354,535	19,373	373,908
	$ 1,739,835	$ 377,561	$ 2,117,396

* Principal and Interest due July 1, 2011.

Nuclear Project No. 3

Fiscal Year	Principal	Interest	Total
6/30/2011 Balance*	$ 103,514	$ 64,997	$ 168,511
2012	69,132	95,934	165,066
2013	131,875	100,433	232,308
2014	124,704	92,367	217,071
2015	151,885	64,116	216,001
2016	264,213	58,814	323,027
2017	211,232	43,694	254,926
2018	404,696	29,230	433,926
Adjustment **	163,664	(163,664)	-
	$ 1,624,915	$ 385,921	$ 2,010,836

* Principal and Interest due July 1, 2011.
** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

Nine Canyon Wind Project

Fiscal Year	Principal	Interest	Total
6/30/2011 Balance*	$ 4,260	$ 3,387	$ 7,647
2012	4,575	6,570	11,145
2013	6,930	6,351	13,281
2014-2017	31,310	21,873	53,183
2018-2021	37,835	15,445	53,280
2022-2025	30,460	7,827	38,287
2026-2029	19,855	3,305	23,160
2030	5,540	249	5,789
	$ 140,765	$ 65,007	$ 205,772

* Principal and Interest due July 1, 2011.

Note 6 - Net Billing

Security - Nuclear Projects Nos. 1 and 3 and Columbia

The 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 13)

Security - Packwood Lake Hydroelectric Project

The Packwood participants and Snohomish PUD have a Power Sales agreement that became effective in October 2008. Under the agreement, Snohomish PUD purchases all of the output directly. The power purchase agreement (PPA) provides a predetermined rate for all firm delivery, per the contract schedule and the Mid-Columbia (Mid-C) based rate for all firm deliveries above firm, or secondary power. Packwood is obligated to supply a specified amount of power. If power production does not supply the required amount of power, Packwood is required to provide any shortfall by purchasing power on the open market which resulted in $17k of purchased power in FY 2011. Conversely, if there is excess capacity per the PPA with Snohomish PUD, Packwood sells the excess on the open market for additional revenues to be included as part of the PPA with the Packwood participants. The Packwood participants are obligated to pay annual costs of the project 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. The Packwood participants also share project revenue to the extent that the amounts exceed project costs.

Note 7 - Pension Plans

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; or it may be downloaded from the DRS website at www.drs.wa.gov. The following disclosures are made pursuant to GASB Statements No. 27, Accounting for Pensions by State and Local Government Employers and No. 50, Pension Disclosures, an Amendment of GASB Statements No. 25 and No. 27.

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 Employees' Retirement System (PERS) Plans 1, 2, and 3

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 members 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 members 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. Notwithstanding, PERS Plan 2 and Plan 3 members may opt out of plan membership if terminally ill, with less than five years to live.

PERS Plan 1 and Plan 2 defined benefit retirement benefits are financed from a combination of investment earnings and employer and employee contributions. PERS retirement benefit provisions are established in chapters 41.34 and 41.40 RCW and may be amended only by the State Legislature.

PERS Plan 1 members are vested after the completion of five years of eligible service. Plan 1 members are eligible for retirement 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 monthly benefit is 2 percent of the average final compensation (AFC) per year of service. (AFC is the monthly average of the 24 consecutive highest-paid service credit months.) The retirement benefit may not exceed 60 percent of AFC. The monthly benefit is subject to a minimum for PERS Plan 1 retirees who have 25 years of service and have been retired 20 years, or who have 20 years of service and have been retired 25 years. Plan 1 members retiring from inactive status prior to the age of 65 may receive actuarially reduced benefits. If a survivor option is chosen, the benefit is further reduced. A cost-of living allowance (COLA) is granted at age 66 based upon years of service times the COLA amount, which is increased 3 percent annually. Plan 1 members may also elect to receive an optional COLA that provides an automatic annual adjustment based on the Consumer Price Index. The adjustment is capped at 3 percent annually. To offset the cost of this annual adjustment, the benefit is reduced.

PERS Plan 1 provides duty and non-duty disability benefits. Duty disability retirement benefits for disablement prior to the age of 60 consist of a temporary life annuity payable to the age of 60. The allowance amount is $350 a month, or two-thirds of the monthly AFC, whichever is less. The benefit is reduced by any workers' compensation benefit and is payable as long as the member remains disabled or until the member attains the age of 60. A member with five years of covered employment is eligible for non-duty disability retirement. Prior to the age of 55, the allowance amount is 2 percent of the AFC for each year of service reduced by 2 percent for each year that the member's age is less than 55. The total benefit is limited to 60 percent of the AFC and is actuarially reduced to reflect the choice of a survivor option. A cost-of living allowance is granted at age 66 based upon years of service times the COLA amount (based on the consumer Price Index), capped at 3 percent annually. To offset the cost of this annual adjustment, the benefit is reduced.

PERS Plan 1 members can receive credit for military service while actively serving in the military, if such credit makes them eligible to retire. Members can also purchase up to 24 months of service credit lost because of an on-the-job injury.

PERS Plan 2 members are vested after the completion of five years of eligible service. Plan 2 members are eligible for normal retirement at the age of 65 with five years of service. The monthly benefit is 2 percent of the AFC per year of service. (AFC is the monthly average of the 60 consecutive highest-paid service months.)

PERS Plan 2 members who have at least 20 years of service credit and are 55 years of age or older are eligible for early retirement with a reduced benefit. The benefit is reduced by an early retirement factor (ERF) that varies according to age, for each year before age 65.

PERS Plan 2 members who have 30 or more years of service credit and are at least 55 years old can retire under one of two provisions:

- With a benefit that is reduced by 3 percent for each year before age 65.
- With a benefit that has a smaller (or no) reduction (depending on age) that imposes stricter return-to-work rules.

PERS Plan 2 retirement benefits are also actuarially reduced to reflect the choice, if made, of a survivor option. There is no cap on years of service credit; and a cost-of-living allowance is granted (based on the Consumer Price Index), capped at 3 percent annually.

The surviving spouse or eligible child or children of a PERS Plan 2 member who dies after leaving eligible employment having earned ten years of service credit may request a refund of the member's accumulated contributions. Effective July 22, 2007, said refund (adjusted as needed for specified legal reductions) is increased from 100 percent to 200 percent of the accumulated contributions if the member's death occurs in the uniformed service to the United States while participating in Operation Enduring Freedom or Persian Gulf, Operation Iraqi Freedom.

PERS 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 monthly benefit that is 1 percent of the AFC per year of service. (AFC is the monthly average of the 60 consecutive highest-paid service months.)

Effective June 7, 2006, PERS 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 for normal retirement at age 65, or they may retire early with the following conditions and benefits:

- If they have at least ten service credit years and are 55 years old, the benefit is reduced by an ERF that varies with age, for each year before age 65.
- If they have 30 service credit years and are at least 55 years old, they have the choice of a benefit that is reduced by 3% for each year before age 65; or a benefit with a smaller (or no) reduction factor (depending on age) that imposes stricter return-to-work rules.

PERS Plan 3 defined benefit retirement benefits are also actuarially reduced to reflect the choice, if made, 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.

PERS Plan 3 defined contribution retirement benefits are solely dependent upon the results of investment activities.

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 Director of the Department of Retirement Systems.

PERS Plan 2 and Plan 3 provide disability benefits. There is no minimum amount of service credit required for eligibility. The Plan 2 monthly benefit amount is 2% of the AFC per year of service. For Plan 3, the monthly benefit amount is 1% of the AFC per year of service.

These disability benefit amounts are actuarially reduced for each year that the member's age is less than 65, and 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 (based on the Consumer Price Index) capped at 3% annually.

PERS Plan 2 and Plan 3 members may have up to ten years of interruptive military service credit; five years at no cost and five years that may be purchased by paying the required contributions. Effective July 24, 2005, a member who becomes totally incapacitated for continued employment while serving the uniformed services, or a surviving spouse or eligible children, may apply for interruptive military service credit. Additionally, PERS Plan 2 and Plan 3 members can also purchase up to 24 months of service credit lost because of an on-the-job injury.

PERS members may also purchase up to five years of additional service credit once eligible for retirement. This credit can only be purchased at the time of retirement and can be used only to provide the member with a monthly annuity that is paid in addition to the member's retirement benefit.

Beneficiaries of a PERS Plan 2 or Plan 3 member with ten years of service who is killed in the course of employment receive retirement benefits without actuarial reduction, if the member was not at normal retirement age at death. This provision applies to any member killed in the course of employment, on or after June 10, 2004, if found eligible by the Department of Labor and Industries.

A one-time duty-related death benefit is provided to the estate (or duly designated nominee) of a PERS member who dies in the line of service as a result of injuries sustained in the course of employment, or if the death resulted from an occupational disease or infection that arose naturally and proximately out of said member's covered employment, if found eligible by the Department of Labor and Industries.

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 1,189 participating employees in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of June 30, 2009:

Retirees and Beneficiaries Receiving Benefits	74,857
Terminated Plan Members Entitled to But Not Yet Receiving Benefits	28,074
Active Plan Members Vested	105,339
Active Plan Members Non-vested	53,896
Total	**262,166**

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 Director of the Department of Retirement Systems 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. As a result of the implementation of the Judicial Benefit Multiplier Program in January 2007, a second tier of employer and employee rates was developed to fund, along with investment earnings, the increased retirement benefits of those justices and judges that participate in the program. 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, 2010, are as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	5.31%**	5.31%**	5.31%***
Employee	6.00%****	3.90%****	*****

* The employer rates include the employer administrative expense fee currently set at 0.16 percent.
** The employer rate for state elected officials is 7.89 percent for Plan 1 and 5.31 percent for Plan 2 and Plan 3.
*** Plan 3 defined benefit portion only.
**** The employee rate for state elected officials is 7.50 percent for Plan 1 and 3.90 percent for Plan 2.
***** Variable from 5.0 percent minimum to 15.0 percent maximum based on rate selected by the PERS 3 member.

Both Energy Northwest and the employees made the required contributions. Energy Northwest's required contributions for the years ending June 30 were as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
2011	$ 184,863	$ 7,921,762	$ 4,281,077
2010	$ 214,117	$ 7,238,997	$ 3,971,410
2009	$ 244,531	$ 6,774,304	$ 2,964,075

Note 8 - Deferred Compensation Plans

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 is a participant during the plan year. The amount of such an employer match shall be 50 percent of the maximum salary deferral percentage. During FY 2011 Energy Northwest contributed $2.9 million in employer matching funds.

Note 9 - Other Employment Benefits – Post-Employment

In addition to the pension benefits available through PERS, Energy Northwest offers post-employment life insurance benefits to retirees who are eligible to receive pensions under PERS Plan 1, Plan 2, and Plan 3. 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 life insurance benefit has a maximum limit of $10,000 for retirees after December 31, 1994. The cost of coverage for retirees remained unchanged for FY 2011 and was $2.82 per $1,000 of coverage. Employees who retired prior to January 1, 1995, contribute $.58 per $1,000 of coverage while Energy Northwest pays the remainder; retirees after December 31, 1994, pay 100 percent of the cost coverage. Premiums are paid to the insurer on a current period basis. At the time each employee retired, Energy Northwest accrued an estimated liability for the actuarial value of the future premium. Energy Northwest revises the liability for the actuarial value of estimated future premiums, net of retiree contributions. The total liability recorded at June 30, 2011, was $0.6 million for these benefits.

During FY 2011, 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 2011 for this and other allocated costs; Columbia at 94 percent; Business Development at 4 percent; and Project 1, Nine Canyon, Packwood and Project 3 receiving the residual amount of 2 percent.

Note 10 - Insurance

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, 2011, the current limit was $12.6 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 $375 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 $117.5 million per reactor, but not more than $17.5 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 $2.8 billion. The deductible for this coverage is $5.0 million per occurrence.

Note 11 - Asset Retirement Obligation (ARO)

Energy Northwest adopted ASC 410 on July 1, 2002. This standard requires an entity to recognize the fair value of a liability of an ARO 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 are discounted using a credit-adjusted-risk-free rate, and are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Capitalized asset retirement costs are depreciated over the life of the related asset with accretion of the ARO liability classified as an operating expense on the statement of operations and Net Assets 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 Washington Energy Facility Site Evaluation Council (EFSEC) and a lease agreement with the DOE. (See Notes 1 and 13) Additionally, there are separate lease agreements for land located at Nine Canyon. Leases at these locations are considered operating leases and expenses were $38.3k for Columbia, $35.0k for Nuclear Project No. 1 and $641.6k for the Nine Canyon project.

As of June 30, 2011, Columbia has a capital decommissioning net asset value of $16.6 million and an accumulated liability of $129.7 million for the generating plant, and for the ISFSI a net asset value of $1.1 million and an accumulated liability of $1.9 million.

Restoration costs incurred in FY 2011 of $0.2 million combined with the current year accretion expense of $0.8 million and downward revision in future restoration estimates of $0.1 million resulted in the small increase to the ARO of $0.5 million. Nuclear Project No. 1 has a capital decommissioning net asset value of zero and an accumulated liability of $15.8 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, 2011, Nine Canyon has a capital decommissioning net asset value of $0.6 million and an accumulated liability of $1.2 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, 2011:

Asset Retirement Obligation (dollars in millions)

Columbia Generating Station		
Balance At June 30, 2010	$	123.22
Current year accretion expense		6.44
ARO at June 30, 2011	$	129.66
ISFSI		
Balance At June 30, 2010	$	1.85
Current year accretion expense		0.09
ARO at June 30, 2011	$	1.94
Nuclear Project No. 1		
Balance At June 30, 2010	$	15.30
Less: Restoration costs incurred		(0.16)
Current year accretion expense		0.79
Revision in future restoration estimates		(0.09)
ARO at June 30, 2011	$	15.84
Nine Canyon Wind Project		
Balance At June 30, 2010	$	1.14
Current year accretion expense		0.05
ARO at June 30, 2011	$	1.19

Note 12 - Decommissioning And Site Restoration

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 (See Note 11 for Columbia ARO). 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 2011.

Energy Northwest's current estimate of Columbia's decommissioning costs in FY 2011 dollars is $463.5 million (Columbia - $459.7 million and ISFSI - $3.8 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 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 $96.4 million in constant dollars (based on the 2011 study) and is updated biannually along with the decommissioning estimate. Both decommissioning and site restoration estimates (based on 2011 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, 2011, totaled approximately $160.3 million and $25.4 million, respectively. Since September 1996, these amounts have been held in an irrevocable trust that recognizes asset retirement obligations according to the fair value of the dismantlement and restoration costs of certain Energy Northwest assets. The trustee is a domestic U.S. bank that certifies the funds for use when needed to retire the asset. The trust is funded by BPA ratepayers and managed by BPA 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 decommissioning and site restoration plan for the ISFSI in 1997. 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, 2011, is $0.9 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 in constant dollars based on the 1997 study.

Note 13 - 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 below under "Nuclear Project No. 1 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 Project No. 1 Site Restoration

Site restoration requirements for Nuclear Project No. 1 is 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 Project No. 1 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 11.

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 by the members and others of a communication network in conjunction with BPA.

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. NoaNet has $14.3 million in network revenue bonds and note payables outstanding,

based on their June 30, 2011 unaudited financial statements. 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 2011 the Business Development Fund contributed $63k to NoaNet based on assessments by the NoaNet members.

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 v. United States of America filed in U.S. Court of Federal Claims in January 2004 (Cause No. 04-0010C). This is an action for breach of contract and breach of implied covenant of good faith and fair dealing brought by Energy Northwest against the United States (Department of Energy, "DOE") for damages for DOE's failure to meet its legal obligations to accept and dispose of spent nuclear fuel and high-level radioactive waste per the Standard Contract. Energy Northwest's claim was in the amount of $56.8 million. A bench trial was conducted in February 2009. The Court issued its opinion in February 2010, awarding Energy Northwest 100% of its claim. The Government appealed approximately $10 million of the trial court's decision. The U.S. Court of Appeals for the Federal Circuit issued its decision on April 7, 2011 affirming the trial court's decision in part, reversing in part, and remanding the case to the trial court for further proceedings. On July 8, 2011, DOE and Energy Northwest filed a Stipulation for Entry of Final Judgment in Favor of Plaintiff Energy Northwest and that same day, the Court of Federal Claims entered Final Judgment in the amount of $48.7 million which was received on August 29, 2011.

Energy Northwest vs. United States of America filed in U.S. Court of Federal Claims in July 2011 (Cause No. 1:11-cv-00447-EJD). This is the second action for breach of contract brought by Energy Northwest against the United States (Department of Energy, "DOE") for damages for DOE's continuing failure to meet its legal obligations to accept and dispose of spent nuclear fuel and high-level radioactive waste per the Standard Contract. The outcome of the litigation is unknown at this time.

Energy Northwest is involved in other 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.

Energy Northwest experienced a significant delay in the completion of R-20. The planned outage extended past the fiscal year-end and was completed in September of 2011. R-20 was planned for 78 days and lasted 174 days. On October 21, 2011, the contractor for the majority of the condenser work for R-20 filed a claim against Energy Northwest for additional costs incurred in connection with the extended outage in the amount of $50 million. The Company intends to vigorously defend against this claim and cannot reasonably estimate the final outcome; however the potential range of exposure is between zero and $50 million. As of June 30, 2011, an accrual has been made for our best estimate of the potential loss within this range.

Note 14 – Derivative Instruments

GASB Statement No. 53, "Accounting and Reporting for Derivative Instruments" was adopted in FY 2010. Energy Northwest's policy is to review and apply as appropriate the normal purchase and normal sales exception under GASB No. 53. Energy Northwest has reviewed various contractual arrangements to determine applicability of this statement. Purchases and sales of nuclear fuel and components that require physical delivery and are expected to be used and/or sold in the normal course of business are generally considered normal purchases and normal sales. These transactions are excluded under GASB No. 53 and therefore are not required to be recorded at fair value in the financial statements. Certain contracts for power options were evaluated and the following contract did not meet the exclusion for normal purchase and normal sale:

The Business Development Fund had a power sales contract subject to the provisions of GASB No. 53. Call options associated with the contract had a notional amount of 50 MWh. The fair value of the power sales option contract is based on the futures price curve for the Mid-Columbia Intercontinental Exchange for electricity and the Sumas index for natural gas. This contract has an end date of June 2013. Assets associated with the call options are classified on the Balance Sheet as deferred charges (other deferred charges) and are currently valued at $0.1 million. Changes in the fair value of the call options are classified as non-operating revenue and expenses – investment income on the Statements of Revenues, Expenses and Changes in Net Assets.

Current Debt Ratings (Unaudited)

		Nine Canyon Rating	
Energy Northwest (Long-Term)	Net-Billed Rating	Phase I & II	Phase III
Fitch, Inc.	AA	A-	A-
Moodys Investors Service, Inc. (Moodys)	Aaa	A3	A3
Standard and Poor's Ratings Services (S & P)	AA	A-	A

PROPOSED FORM OF OPINION OF BOND COUNSEL
FOR THE SERIES 2012-D/E BONDS

Energy Northwest

Merrill Lynch, Pierce, Fenner & Smith Incorporated

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

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 $34,140,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-D and its $748,515,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable) (together, the "2012-D/E Bonds"). The 2012-D/E Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. 1042 (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on October 23, 1997, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on July 26, 2012 (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 2012-D/E Bonds are subject to redemption prior to their stated maturities. The 2012-D/E 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 2012-D/E Bonds and apply the proceeds of the 2012-D/E 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 Bond Resolutions to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the Electric Revenue Bonds, including the 2012-D/E Bonds, and the 2012-D/E Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2012-D/E 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 2012-D/E Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2012-D/E 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 2012-D/E 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 OPINION OF BOND COUNSEL FOR THE SERIES 2012-D/E BONDS

Energy Northwest

Merrill Lynch, Pierce, Fenner & Smith Incorporated

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

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 $34,140,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-D and its $748,515,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable) (together, the "2012-D/E Bonds"). The 2012-D/E Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. 1042 (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on October 23, 1997, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on July 26, 2012 (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 2012-D/E Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. 2 Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. 2 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 an Assistant Treasurer of Energy Northwest, 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) 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 and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville 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 FOR THE SERIES 2012-D/E BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$34,140,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-D
$748,515,000 Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable)

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 $34,140,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2012-D (the “Series 2012-D Bonds”) and $748,515,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2012-E (Taxable) (the “Series 2012-E (Taxable) Bonds”).

The Series 2012-D Bonds and the Series 2012-E (Taxable) Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the “Act”) and Resolution No. 1042, adopted by Energy Northwest on October 23, 1997, as amended and supplemented, and a supplemental resolution adopted on July 26, 2012 (the “Columbia Resolution”). The Columbia Resolution provides that the Series 2012-D Bonds are being issued for the purpose of paying costs of replacing the main condenser and various other capital improvements to the Columbia Generating Station and paying costs of issuing the Series 2012-D Bonds. The Columbia Resolution provides that the Series 2012-E (Taxable) Bonds are being issued for the purpose (directly or indirectly through repayment of the Columbia Note) of paying the costs of acquiring fuel for the Columbia Generating Station; financing repairs, renewals and improvements or betterments to and operating expenses of the Columbia Generating Station; repaying bonds of the Columbia Generating Station, if proceeds are not needed for the prior purposes, capitalizing interest, and paying costs of issuing the Series 2012-E (Taxable) 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 by the Bonneville Power Administration on the date hereof (collectively, the “Tax Certificates”); the opinions of Foster Pepper PLLC, as Bond Counsel, dated the date hereof (the “Bond Counsel Opinions”); 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 2012-D Bonds and Series 2012-E (Taxable) 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, all 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 fourth 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 2012-D Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2012-D Bonds, the Series 2012-E (Taxable) Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors’ rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated August 15, 2012 relating to the Series 2012-D Bonds and Series 2012-E (Taxable) Bonds, or other offering material relating to those Bonds and express no opinion with respect thereto.

We have relied with your consent on the Bond Counsel Opinions with respect to the validity of the Series 2012-D Bonds and Series 2012-E (Taxable) and with respect to the due authorization and issuance of the Series 2012-D Bonds and Series 2012-E (Taxable) Bonds.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. Interest on the Series 2012-D Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code").

2. Interest on the Series 2012-D Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. We observe, however, that interest on the Series 2012-D Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

3. Interest on the Series 2012-E (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 Internal Revenue Code of 1986, as amended.

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 2012-E (Taxable) Bonds.

Series 2012-E (Taxable) Bonds Circular 230 Disclaimer:

Investors are urged to obtain independent tax advice regarding the Series 2012-E (Taxable) Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2012-E (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 2012-E (Taxable) Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2013 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	0.423		
	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 2013 are 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 Project; (iii) to construct the 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

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 Resolution authorizing the Series 2012-D/E Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2012-D/E 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. There are no Columbia prior lien bonds outstanding.

"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.

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 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 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 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 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 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 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 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 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.

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 THE PROJECT 1 AND PROJECT 3 PRIOR LIEN RESOLUTIONS

The following summary is a brief outline of certain provisions contained in the Project 1 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 and Project 3 Prior Lien Bonds (together, the "Prior Lien Bonds"). There are no Columbia prior lien bonds outstanding.

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:

(1) the amount included in the annual budget for fuel adopted pursuant to the Project 1 Project Agreement,

(2) all amounts received by Energy Northwest as fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(3) 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.

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 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, 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; (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 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, as may be decided upon by Energy Northwest and Bonneville with the approval of the Consulting Engineer. In addition, if Energy Northwest and Bonneville agree, all or any part of such excess over required working capital for a Net Billed Project may be applied to the making of repairs, renewals, replacements, additions, betterments and improvements to, and extensions of, such Project, the purchase or redemption of Bonds for such Project or for other purposes in connection with such Project.

Certain Covenants

Certain covenants of Energy Northwest with the holders of the Prior Lien Bonds are summarized as follows:

The Hanford Project: Under the Project 1 Prior Lien Resolution, Energy Northwest covenants that it (a) will not issue any evidences of indebtedness under Resolution No. 178 so long as the obligations of said resolution are satisfied under the Project 1 Prior Lien Resolution, (b) will discharge all of its duties and obligations under Resolution No. 178, (c) will make all payments and deposits to be made under the provisions of Resolution No. 178 from moneys to be provided pursuant to the Project 1 Prior Lien Resolution if and to the extent such obligations are not otherwise provided for, (d) will, on each December 31, apply any excess of amounts in the Hanford Project Revenue Fund over the required amount of working capital to reduce the amounts required by the Project 1 Prior Lien Resolution to be deposited in the Hanford Project Revenue Fund, and (e) will not amend Resolution No. 178 in any manner which adversely affects the rights of Bondholders under the Project 1 Prior Lien Resolution.

The Net Billed Projects: Energy Northwest covenants that it will, subject to the Project Agreements for each of the Net Billed Projects, complete construction of the Net Billed Projects at the earliest practicable time, operate such Projects and the business in connection therewith in an efficient manner and at reasonable cost, maintain such Projects in good condition and make all necessary and proper repairs, renewals, replacements, additions, extensions and betterments to such Projects.

Rates: Energy Northwest covenants that it will dispose of all capability of and power and energy from Project 1 solely for the benefit and account of such Project and pursuant to the provisions of the Project 1 Net Billing Agreements; and Energy Northwest covenants that it will maintain and collect rates and charges for capability, power and energy and other services, facilities and commodities sold, furnished or supplied through such Project, which will be adequate, whether or not the generation or transmission of power by such Project is suspended, interrupted or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to make the required payments into the Hanford Project Revenue Fund, (ii) to pay the expenses of operating and maintaining Project 1, (iii) to make the required payments into the Project No. 1 Bond Funds, and (iv) to make the payments required into certain funds under the Project 1 Prior Lien Resolution.

Energy Northwest covenants that it will dispose of all capability of and power and energy from 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 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 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, 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 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 or Project 3 Prior Lien Bonds (as the case may be) shall have the right to declare the Project 1 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 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 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.

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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 Series 2012-D/E Bonds. The Series 2012-D/E 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 Series 2012-D/E Bond certificate will be issued for each maturity of the Series 2012-D/E Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 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"). 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 Series 2012-D/E 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 Series 2012-D/E Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bonds, except in the event that use of the book entry-entry system for the Series 2012-D/E Bonds is discontinued.

To facilitate subsequent transfers, all Series 2012-D/E 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 Series 2012-D/E Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2012-D/E Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the Series 2012-D/E 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 Series 2012-D/E 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, Series 2012-D/E 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, Series 2012-D/E Bond certificates will be printed and delivered to DTC.

With respect to Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bond is registered on the Bond Register, as the holder and absolute owner of such Series 2012-D/E Bond for the purpose of payment of principal and interest with respect to such Series 2012-D/E Bond, for the purpose of giving notices of redemption and other matters with respect to such Series 2012-D/E Bond, for the purpose of registering transfers with respect to such Series 2012-D/E 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 Series 2012-D/E Bonds.

APPENDIX J

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENT

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville entered into a written agreement (the "Disclosure Agreement") for the benefit of the holders and beneficial owners of the Series 2012-D/E Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreement, which apply to any capitalized term used in the Disclosure Agreement, the following capitalized terms shall have the following meanings:

"BPA Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the Series 2012D/E 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 Series 2012-D/E Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of July 2, 2012" 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 the MSRB.

"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 the MSRB.

"MSRB" means the Municipal Securities Rulemaking Board or any successors to its functions.

"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.

Financial Information.

Bonneville. Bonneville agrees to provide to the MSRB, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2012:

(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 the MSRB, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with the Energy Northwest Fiscal Year ending June 30, 2012:

(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 specifically cross-reference other documents available to the public on the internet website of the MSRB, or filed with the SEC.

Notice of Failure to Provide Financial Information. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to the MSRB (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.

Events Notices.

Energy Northwest agrees to provide or cause to be provided, in a timely manner (not in excess of ten business days after the occurrence of the event), to the MSRB, notice of the occurrence of any of the following events with respect to the Series 2012-D/E Bonds:

i. Principal and interest payment delinquencies;

ii. Non-payment related defaults, if material;

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, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notice of Proposed Issue (IRS Form 5701 – TEB) or other material notices or determinations with respect to the tax status of the Series 2012-D/E Bonds;

vii. Modifications to rights of Series 2012-D/E Bondholders, if material;

viii. Optional, contingent or unscheduled calls of any Series 2012-D/E Bonds other than scheduled sinking fund redemptions for which notice is given pursuant to Exchange Act Release 34-23856, if material, and tender offers;

ix. Defeasances;

x. Release, substitution or sale of property securing repayment of the Series 2012-D/E Bonds, if material;

xi. Rating changes;

xii. Bankruptcy, insolvency, receivership or similar event of Energy Northwest (a "Bankruptcy Event")'

xiii. The consummation of a merger, consolidation, or acquisition involving Energy Northwest or the sale of all or substantially all of the assets of Energy Northwest, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and

xiv. Appointment of a successor or additional trustee or the change of name of a trustee, if material.

A Bankruptcy Event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for Energy Northwest in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of Energy Northwest, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person.

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 Series 2012-D/E Bonds.

Availability of Information from the MSRB.

Bonneville and Energy Northwest have agreed to provide the foregoing information only to the MSRB. The information filed with the MSRB is 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 timely notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Series 2012-D/E 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 Series 2012-D/E Bonds; and (ii) notifies the MSRB 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 listed event under "Events Notices," and (ii) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Remedies.

The right of any Owner or Beneficial Owner of Series 2012-D/E 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 Series 2012-D/E 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 Series 2012-D/E Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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ENERGY NORTHWEST • COLUMBIA GENERATING STATION ELECTRIC REVENUE BONDS, SERIES 2012-D AND SERIES 2012-E (TAXABLE)

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