NEW ISSUE — BOOK-ENTRY ONLY

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 2014-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended, and Section 103 of the Internal Revenue Code of 1954, as amended. In the further opinion of Special Tax Counsel, interest on the Series 2014-C Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings when calculating federal corporate alternative minimum taxable income. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on the Series 2014-C Bonds. See "TAX MATTERS" herein.

ENERGY NORTHWEST

$269,415,000
ENERGY NORTHWEST

$197,110,000 Project 1 Electric Revenue Refunding Bonds, Series 2014-C
$72,305,000 Project 3 Electric Revenue Refunding Bonds, Series 2014-C

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

The Project 1 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 1 2014-C Bonds") are being issued to repay a portion or all of the principal portion of the Project 1 Note (as described herein) used to pay principal on certain outstanding Project 1 Electric Revenue Bonds that matured on July 1, 2014, as more fully described herein. The Project 3 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 3 2014-C Bonds," and together with the Project 1 2014-C Bonds, the "Series 2014-C Bonds") are being issued to repay a portion or all of the principal portion of the Project 3 Note (as described herein) used to pay principal on certain outstanding Project 3 Electric Revenue Bonds that matured on July 1, 2014. See "PURPOSE OF ISSUANCE" herein.

The Series 2014-C 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 2014-C 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 2014-C 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 2014-C Bonds. Principal of the Series 2014-C Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., as Trustee for the Series 2014-C Bonds. Interest on the Series 2014-C Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2015. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2014-C 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 2014-C BONDS—GENERAL—Book-Entry System; Transferability and Registration" and Appendix I—"BOOK-ENTRY SYSTEM" herein.

The Series 2014-C Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE SERIES 2014-C BONDS—REDEMPTION" *herein.*

The Series 2014-C 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 2014-C Bonds are payable as provided herein on a subordinated basis to the Prior Lien Bonds. The Series 2014-C 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. Project 1 and Project 3 are separate projects of Energy Northwest, and each Series of Series 2014-C Bonds is payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover Page

The Series 2014-C 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 LLP, New York, New York, a member of Norton Rose Fulbright, Counsel to the Underwriters. It is expected that the Series 2014-C Bonds will be available for delivery through the facilities of DTC on or about August 21, 2014.

J.P. Morgan **Citigroup** **Goldman, Sachs & Co.** **BofA Merrill Lynch**

August 5, 2014

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

THE SERIES 2014-C BONDS

$197,110,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP No.*
2025	$ 62,525,000	5.00%	2.64%**	29270CF83
2026	65,650,000	5.00	2.74**	29270CF91
2027	68,935,000	5.00	2.82**	29270CG25

$72,305,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP No.*
2028	$ 72,305,000	5.00%	2.91%**	29270CG33

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* 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, 2024 par call date.

ENERGY NORTHWEST
P.O. Box 968
Richland, Washington 99352
Telephone (509) 372-5000

Executive Board Members

Administrative Staff

Chief Executive Officer	Mark E. Reddemann
Vice President, Nuclear Generation/Chief Nuclear Officer	Brad J. Sawatzke
Vice President, Corporate Services/Chief Financial Officer	Brent J. Ridge
Vice President, Engineering	Alex Javorik
Vice President, Operations	William G. Hettel
General Manager, Energy Services and Development	James W. Gaston
General Counsel	Robert Dutton

Financial Advisor	*Bond and Disclosure Counsel*	*Trustee for the Series 2014-C Bonds*
Public Financial Management, Inc.	Foster Pepper PLLC	The Bank of New York Mellon Trust Company, N.A.

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
Portland, Oregon 97208
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Administrator and Chief Executive Officer	Elliot E. Mainzer
Deputy Administrator	Gregory K. Delwiche
Chief Operating Officer	Claudia R. Andrews
Executive Vice President and General Counsel (Acting)	Mary K. Jensen
Executive Vice President and Chief Financial Officer (Acting)	Nancy M. Mitman

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 2014-C 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 2014-C 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 2014-C BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF THE SERIES 2014-C BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

TABLE OF CONTENTS

APPENDICES

OFFICIAL STATEMENT

$269,415,000

ENERGY NORTHWEST

$197,110,000 Project 1 Electric Revenue Refunding Bonds, Series 2014-C
$72,305,000 Project 3 Electric Revenue Refunding Bonds, Series 2014-C

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of the Series 2014-C Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the Series 2014-C 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 $197,110,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 1 2014-C Bonds") and $72,305,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 3 2014-C Bonds," and, together with the Project 1 2014-C Bonds, the "Series 2014-C Bonds").

The Project 1 2014-C Bonds are being issued pursuant to Chapters 39.46, 39.53 and 43.52 of the Revised Code of Washington, as amended (the "Act") and Resolution No. 835 adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 1811 adopted on July 24, 2014, the "Project 1 Electric Revenue Bond Resolution") for the purpose of repaying the Project 1 Note (as described herein) that was used to pay a portion or all of the principal portion of certain outstanding Project 1 Electric Revenue Bonds that matured on July 1, 2014. Energy Northwest has other 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." Bonds issued pursuant to the Project 1 Electric Revenue Bond Resolution are referred to herein as the "Project 1 Electric Revenue Bonds."

The Project 3 2014-C Bonds are being issued pursuant to the Act and Resolution No. 838, adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 1812 adopted on July 24, 2014, the "Project 3 Electric Revenue Bond Resolution") for the purpose of repaying the Project 3 Note (as described herein) that was used to pay a portion or all of the principal portion of certain outstanding Project 3 Electric Revenue Bonds that matured on July 1, 2014. Energy Northwest has other indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution. In addition, Energy Northwest has other 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 together with the Project 1 Prior Lien Bonds, the "Prior Lien Bonds." Bonds issued pursuant to the Project 3 Electric Revenue Bond Resolution are referred to herein as the "Project 3 Electric Revenue Bonds."

Energy Northwest may issue bonds for the Columbia Generating Station ("Columbia" or the "Columbia Generating Station") pursuant to the Act and Resolution No. 1042, adopted on October 23, 1997 (as amended and supplemented, the "Columbia Electric Revenue Bond Resolution," and together with the Project 1 Electric Revenue Bond Resolution and the Project 3 Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions"). Bonds issued pursuant to the Columbia Electric Revenue Bond Resolution are referred to herein as the "Columbia Electric Revenue Bonds," and together with the Project 1 Electric Revenue Bonds and the Project 3 Electric Revenue Bonds, are collectively referred to herein as the "Electric Revenue Bonds." Energy Northwest is not issuing any Columbia Electric Revenue Bonds at this time.

The Prior Lien Bonds, the Electric Revenue Bonds, including the Series 2014-C Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Subordinated Resolutions are collectively referred to herein as the "Net Billed Bonds."

For additional information relating to the Project 1 Note and the Project 3 Note to be repaid, see "PURPOSE OF ISSUANCE" in this Official Statement.

ENERGY NORTHWEST

Energy Northwest was organized in 1957 as the Washington Public Power Supply System. By resolution of its Executive Board adopted on June 2, 1999, the Washington Public Power Supply System officially changed its name to Energy Northwest. In 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. In 2012, Public Utility District No. 1 of Whatcom County withdrew as 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"). Project 1 and Project 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. Project 1, Project 3 and Columbia are collectively referred to herein as the "Net Billed Projects." Each of Project 1, Project 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 meet the costs of 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 credits and cash 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 2014-C BONDS

The Project 1 2014-C Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2014-C Bonds are secured, on a subordinated basis to the Project 1 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2014-C Bonds are secured on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 1 Electric Revenue

Bond Resolution or any Project 1 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

The Project 3 2014-C Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2014-C Bonds are secured, on a subordinated basis to the Project 3 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2014-C Bonds are secured on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

There are no restrictions 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 Revenue Bonds.

The Project 1 2014-C Bonds are secured on a subordinated basis to the Project 1 Prior Lien Bonds from amounts derived pursuant to Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The Project 3 2014-C Bonds are secured on a subordinated basis to the Project 3 Prior Lien Bonds from amounts derived pursuant to Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The receipts, income and revenues derived from a Project secure only the Series 2014-C Bonds and other Electric Revenue Bonds relating to that Project. Accordingly, the owners of the Series 2014-C Bonds issued for a particular Project will have no claim on the receipts, income and revenues securing any other Energy Northwest Project. For further information, see "SECURITY FOR THE NET BILLED BONDS" in this Official Statement.

For further information on the Net Billed Bonds outstanding as of July 1, 2014, see "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" in this Official Statement.

NET BILLING AGREEMENTS

Under the Net Billing Agreements, the Participants in each Net Billed Project have contracted to purchase the capability of that Net Billed Project and have agreed to provide Energy Northwest with funds necessary to meet the costs of that Net Billed Project. These costs include the amounts that Energy Northwest is obligated to pay in each contract year into the various funds provided for in the Prior Lien Resolution and Electric Revenue Bond Resolution related to Project 1 and Project 3 for debt service and for all other purposes of Project 1 and Project 3. These costs include the amounts that Energy Northwest is obligated to pay in each contract year into the various funds provided for in the Columbia Electric Revenue Bond Resolution for debt service and for all other purposes of Columbia. 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 2014-C BONDS

GENERAL

The Series 2014-C 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 2014-C Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2015, at the rates shown on the inside cover page of this Official Statement. Interest on the Series 2014-C 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., has been appointed the Trustee, Paying Agent and Registrar for the Series 2014-C Bonds (collectively, the "Trustee"). For so long as the Series 2014-C 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 2014-C 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 2014-C Bonds will not receive certificates representing their interests in such Series 2014-C Bonds purchased, except as described in Appendix I—"BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as initial securities depository for each Series of Series 2014-C Bonds. As discussed in Appendix I—"BOOK-ENTRY SYSTEM," transfers of ownership interests in the Series 2014-C 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 2014-C Bonds. Energy Northwest, the Trustee and any other person may treat the registered owner of any Series 2014-C Bonds as the absolute owner of such Series 2014-C 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 2014-C Bonds shall be overdue or not. All payments of or on account of interest or principal to any registered owner of any such Series 2014-C 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 2014-C Bonds, to the extent of the sum or sums paid.

When Series 2014-C 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 2014-C 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 2014-C 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 2014-C 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, or premium, if any, or interest on the Series 2014-C 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 2014-C 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 2014-C Bond is registered, as the holder and absolute owner of such Series 2014-C 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 2014-C Bonds, Series 2014-C Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the Series 2014-C Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the Series 2014-C Bonds will be payable by check or draft mailed to the persons in whose names such Series 2014-C Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date; provided, however, that upon the written request of a registered owner of at least $1,000,000 in aggregate principal amount of a Series of the Series 2014-C 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 2014-C Bonds is discontinued, registered ownership of any Series 2014-C Bond may be transferred or exchanged by surrendering such Series 2014-C Bond to the Trustee, with the assignment form appearing on the Series 2014-C Bond duly executed. The Trustee shall not be required to transfer any Series 2014-C Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

The Series 2014-C Bonds are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2024, 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 2014-C Bonds to be redeemed, plus interest accrued to the date of redemption.

Partial Redemption

If less than all of the Series 2014-C 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 2014-C Bonds of a Series of any maturity are to be redeemed, the Series 2014-C Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot or in accordance with their respective standard procedures. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any Series 2014-C 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 2014-C Bonds for redemption, the Trustee will treat each such Series 2014-C Bonds as representing that number of such Series 2014-C Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2014-C Bonds to be redeemed in part by $5,000.

Notice of Redemption

Notice of redemption of any Series 2014-C 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 2014-C Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2014-C Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2014-C 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 2014-C Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2014-C 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 2014-C Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2014-C Bonds on the redemption date and the Series 2014-C 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 2014-C Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2014-C 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 2014-C 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 2014-C Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2014-C 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 2014-C Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any Series 2014-C 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 2014-C Bond, and such Series 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C Bonds.

PURPOSE OF ISSUANCE

The Project 1 2014-C Bonds are being issued for the purpose of repaying the Project 1 Note described in this paragraph. JPMorgan Chase Bank, National Association extended a line of credit to Energy Northwest for Project 1 and for Project 3 pursuant to a Loan Agreement dated June 19, 2014 (the "Loan Agreement"). Under the Loan Agreement, Energy Northwest borrowed $235,445,000 to repay all or a portion of the principal portion of certain Project 1 Electric Revenue Bonds that matured on July 1, 2014. Energy Northwest's obligation to repay the advance under the Loan Agreement for this purpose is evidenced by a bond anticipation note (the "Project 1 Note") executed and delivered by Energy Northwest pursuant to a Separate Subordinated Resolution adopted on May 15, 2014 (the "Note Resolution"). The Project 1 Note is secured on a parity with the Project 1 Electric Revenue Bonds issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Project 1 Separate Subordinated Resolutions.

The Project 3 2014-C Bonds are being issued for the purpose of repaying the Project 3 Note described in this paragraph. Under the Loan Agreement, Energy Northwest borrowed $85,180,000 to repay all or a portion of the principal portion of certain Project 3 Electric Revenue Bonds that matured on July 1, 2014. Energy Northwest's obligation to repay the advance under the Loan Agreement for this purpose is evidenced by a bond anticipation note (the "Project 3 Note") executed and delivered by Energy Northwest pursuant to the Note Resolution. The Project 3 Note is secured on a parity with the Project 3 Electric Revenue Bonds issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Project 3 Separate Subordinated Resolutions.

SOURCES AND USES OF FUNDS

SOURCES OF FUNDS

Project 1	
Principal of Project 1 2014-C Bonds	$ 197,110,000
Original Issue Premium	38,333,445
Energy Northwest Equity Contribution	1,318,411
Total	$ 236,761,856
Project 3	
Principal of Project 3 2014-C Bonds	$ 72,305,000
Original Issue Premium	12,871,013
Energy Northwest Equity Contribution	487,043
Total	$ 85,663,056

USES OF FUNDS

Project 1	
Project 1 Note Repayment	$ 235,445,000
Costs of issuing Project 1 2014-C Bonds (including Underwriters' compensation)	1,316,856
Total	$ 236,761,856
Project 3	
Project 3 Note Repayment	$ 85,180,000
Costs of issuing Project 3 2014-C Bonds (including Underwriters' compensation)	483,056
Total	$ 85,663,056

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2014-C Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 1 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 1, which pledge is subject, so long as any of the Project 1 Prior Lien Bonds remain outstanding ($41,070,000 of which were outstanding as of July 1, 2014), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2014-C Bonds are a charge on the receipts, income and revenues of Project 1 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 1 Prior Lien Resolution and payments required to be made under the Project 1 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 1, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 1 Electric Revenue Bonds are also secured by a pledge of the proceeds of the sale of Project 1 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 1 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 1 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 1 Electric Revenue Bond Resolution, the Project 1 2014-C Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 1 Separate Subordinated Resolution. There were outstanding as of July 1, 2014, $674,835,000 principal amount of Project 1 Electric Revenue Bonds.

The Project 3 2014-C Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 3 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 3, which pledge is subject, so long as any of the Project 3 Prior Lien Bonds remain outstanding ($136,935,000 of which were outstanding as of July 1, 2014), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2014-C Bonds are a charge on the receipts, income and revenues of Project 3 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 3 Prior Lien Resolution and payments required to be made under the Project 3 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 3, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 3 Electric Revenue Bonds are also secured by a pledge of the proceeds of the sale of Project 3 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 3 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 3 Electric Revenue Bond

Resolution, including the investments, if any, therein. Under the Project 3 Electric Revenue Bond Resolution, the Project 3 2014-C Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 3 Separate Subordinated Resolution. There were outstanding as of July 1, 2014, $934,465,000 principal amount of Project 3 Electric Revenue Bonds.

As of July 1, 2014, there were $3,304,805,000 principal amount of Columbia Electric Revenue Bonds outstanding. There are no Columbia bonds outstanding that have a lien on revenues that is prior to the lien of the Columbia 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 Resolutions.

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 2014-C 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, including the Project 1 2014-C Bonds. See "NET BILLING AND RELATED AGREEMENTS."

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 2014-C 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, including the Project 3 2014-C Bonds. See "NET BILLING AND RELATED AGREEMENTS."

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 any Columbia Electric Revenue 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. See "NET BILLING AND RELATED AGREEMENTS." There are no Columbia Electric Revenue Bonds being issued at this time.

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 information sufficient to cover its obligations under the Net Billing Agreements, including the payment of debt service on the Net Billed Bonds. Bonneville may make such expenditures without further appropriation and without fiscal year limitation, but subject to such specific directives or limitations on use of the Bonneville Fund as may be included by Congress in appropriation acts. The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund" in this Official Statement.

The Project 1 2014-C Bonds and the Project 3 2014-C Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2014-C Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 3 2014-C Bonds. The owners of the Project 3 2014-C Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2014-C Bonds. No Bondholder has a claim on the assets of any Project.

The Series 2014-C 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 2014-C 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 (Section 801)."

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 Resolutions, 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 2014-C 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 Project 1 Note and the Project 3 Note described under "PURPOSE OF ISSUANCE" are also subject to acceleration under the Loan Agreement.

If there is an acceleration of a maturity of the Prior Lien Bonds or Electric Revenue Bonds, Bonneville has taken the position since at least 1989, that Bonneville's and the Participant's obligations to make payments under the Net Billing Agreements would remain as though no such acceleration had occurred. If Bonneville and the Participants were obligated only to provide funds to meet the scheduled amounts due on the Project 1 Prior Lien Bonds and not the amounts due upon acceleration, money intended to be applied to the payment of the Project 1 Electric Revenue Bonds, including the Project 1 2014-C Bonds, would be applied by the Project 1 Prior Lien Bond Fund Trustee to payment of such Project 1 Prior Lien Bonds, and the Project 1 Electric Revenue Bonds, including the Project 1 2014-C Bonds, would not be paid until such Project 1 Prior Lien Bonds ceased to be outstanding or the Event of Default giving rise to such acceleration were cured. If Bonneville and the Participants were obligated only to provide funds to meet the scheduled amounts due on the Project 3 Prior Lien Bonds and not the amounts due upon acceleration, money intended to be applied to the payment of the Project 3 Electric Revenue Bonds, including the Project 3 2014-C Bonds, would be applied by the Project 3 Prior Lien Bond Fund Trustee to payment of such Project 3 Prior Lien Bonds, and the Project 3 Electric Revenue Bonds, including the Project 3 2014-C Bonds, would not be paid until such 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 Project 1 Prior Lien Resolution and Project 3 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, as applicable, payment of the principal of and interest on the Series 2014-C 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 2014-C Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the Series 2014-C 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 2014-C Bonds may be limited by and are subject to bankruptcy, insolvency, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases. The opinions to be delivered by Foster Pepper PLLC, as Bond Counsel, concurrently with the issuance of the Series 2014-C Bonds will be subject to such limitations. See Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2014-C BONDS," and Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2014-C BONDS."

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the Series 2014-C Bonds. In the Electric Revenue Bond Resolutions, Energy Northwest has reserved the right to create a reserve account to secure a separate series of Electric Revenue Bonds.

ADDITIONAL INDEBTEDNESS

The Project 1 Electric Revenue Bonds are subordinate to the Project 1 Prior Lien Bonds. The Project 3 Electric Revenue Bonds are subordinate to the Project 3 Prior Lien Bonds. In each Electric Revenue Bond Resolution, Energy Northwest has reserved the right to issue, upon satisfaction of certain conditions set forth therein, additional bonds or notes under the Electric Revenue Bond Resolutions 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 Project 1 Note that is to be paid from a portion of the proceeds of the Project 1 2014-C Bonds and the Project 3 Note that is to be paid from a portion of the proceeds of the Project 3 2014-C Bonds were 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 2014-C Bonds, pursuant to Separate Subordinated Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist under the applicable Electric Revenue Bond Resolution.

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

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

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

NET BILLING AND RELATED AGREEMENTS

General

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (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 2014 BUDGETS" for a list of Participants and their respective shares of the Projects' fiscal year 2014 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 "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 amounts received by 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; however, in fiscal year 2013, Bonneville and four Preference Customers (each of which is a Net Billing Participant) agreed to separate electricity prepayment arrangements in which the Preference Customers provided lump-sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028. The participating customers are entitled to future deliveries of a portion of the electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments is and will be reflected as fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville received $340 million in aggregate of prepayments from the participating customers. The offsetting prepayment credits are set at $2.55 million per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028. While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use this form of Non-Federal Debt to meet some of its capital funding needs.

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 2013 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, 2013" 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, 2013. 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 1, 2014. For information with respect to the Project 1 Note and Project 3 Note issued on June 19, 2014, see "PURPOSE OF ISSUANCE."

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF JULY 1, 2014

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 41,070,000
Electric Revenue Refunding Bonds	674,835,000
TOTAL PROJECT 1	$ 715,905,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 0
Electric Revenue and Refunding Bonds	3,304,805,000
TOTAL COLUMBIA	$ 3,304,805,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 136,935,000(1)
Electric Revenue Refunding Bonds	934,465,000
TOTAL PROJECT 3	$ 1,071,400,000
TOTAL NET BILLED REVENUE BONDS	$ 5,092,110,000
Nine Canyon Wind Project Revenue Bonds (2)	$ 112,120,000

(1) Includes $44,453,317 accreted value of Compound Interest Bonds for Project 3, as of July 1, 2014.
(2) Bonneville is not a party to any agreements that secure payment of the Nine Canyon Wind Project Revenue Bonds.

On June 26, 2014, the Energy Northwest Executive Board adopted a motion supporting the issuance of the Series 2014-C Bonds to increase the weighted average maturities of outstanding Project 1 and Project 3 bonds to match more closely the originally expected useful lives of Project 1 and Project 3. The refinancing of certain Project 1 and Project 3 bonds, which matured on July 1, 2014, with later maturing Project 1 and Project 3 Series 2014-C Bonds will make available Bonneville revenues in the current year, thereby enabling Bonneville to advance the repayment of a like amount of certain of Bonneville's repayment obligations to the United States Treasury. More particularly, Bonneville will prepay a portion of its repayment obligations with respect to amounts appropriated by Congress for federally-owned hydroelectric facilities of the Federal System. These federal repayment obligations bear interest at a rate that is higher than the rates of interest on the Series 2014-C Bonds.

Bonneville has asked Energy Northwest to consider issuing similar refunding bonds in the future for Project 1, Project 3 and Columbia. The Energy Northwest Executive Board is considering this request, which is known as the regional cooperation debt proposal. As with the Series 2014-C Bonds, these proposed refinancing efforts would make available Bonneville revenues in future years, thereby enabling Bonneville to prepay certain of Bonneville's United States Treasury repayment obligations. With respect to the issuance of Columbia refunding bonds, the restructuring may involve freeing up Bonneville revenues to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury in addition to the prepayment of a portion of the appropriated Federal investment in the power facilities of the Federal System. On June 26, 2014, the Energy Northwest Executive Board also adopted a motion supporting the issuance of up to $6 million in Columbia refunding bonds in 2016 and 2017 to increase the weighted average maturities of certain outstanding Columbia bonds to match more closely the originally expected useful lives of facilities refinanced by those proposed Columbia refunding bonds.

In the past, Energy Northwest and Bonneville have worked together to refinance certain maturities of Project 1, Project 3 and Columbia bonds with series of refunding bonds having later maturities so that the weighted average maturities of outstanding Project 1, Project 3 and Columbia bonds more closely matched the originally expected useful lives of the refinanced Project 1, Project 3 and Columbia facilities, respectively. Between 2001 and 2009, these refundings were known as the Debt Optimization Program. By extending maturities of outstanding bonds, these refundings made available Bonneville revenues which were then used to prepay a portion of Bonneville's federal appropriations repayment obligations and to pay down the outstanding balance of the then-outstanding bonds issued by Bonneville to the United States Treasury, thereby increasing the borrowing capacity available to Bonneville under its authority to borrow from the United States Treasury. The regional cooperation debt proposal is similar in certain respects to these prior transactions.

Bonneville manages its overall debt portfolio to meet the objectives of (1) minimizing the cost of federal and non-federal 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" in Appendix A.

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 (1) 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; (2) 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 (3) 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, Chair	Retired Executive	June 2017
Jack Janda, Vice Chair	Public Utility District Commissioner	June 2018
Lori Kays-Sanders, Secretary	Public Utility District Commissioner	June 2018
David Remington, Assistant Secretary	Financial Consultant	June 2016
Marc Daudon	Management Consultant	June 2018
Linda Gott	Public Utility District Commissioner	June 2018
James Moss	Director of Energy, United Association of Plumbers & Pipefitters	June 2018
Skip Orser	Retired Nuclear Executive	June 2018
Will Purser	Public Utility District Commissioner	June 2018
Tim Sheldon	Washington State Senator	June 2016
Kathleen Vaughn	Public Utility District Commissioner	June 2018

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	35 years
Bradley J. Sawatzke	Vice President, Nuclear Generation/Chief Nuclear Officer	31 years
Alex Javorik	Vice President, Engineering	33 years
William G. Hettel	Vice President, Operations	30 years
James W. Gaston	General Manager, Energy Services and Development	20 years
		Experience
Brent J. Ridge	Vice President, Corporate Services/Chief Financial Officer	24 years
Robert A. Dutton	General Counsel	26 years

EMPLOYEES

Energy Northwest currently employs approximately 1,236 employees. Of these employees, 308 are members of the International Brotherhood of Electrical Workers ("IBEW"), 140 are members of the United Steel Workers ("USW") and six 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 bargaining agreements have been renegotiated and extend to either 2015 or 2016 depending on the agreement. 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 certain retirement plans administered by the State of Washington. In addition, Energy Northwest 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, 2013, attached hereto as Appendix C.

Energy Northwest participates in the State Public Employees Retirement System ("PERS"), which consists of defined benefit Plans 1 and 2 and a hybrid defined benefit/defined contribution Plan 3. PERS participants who joined the system by September 30, 1977 are Plan 1 members. Members now have the option of choosing Plan 2 or Plan 3. The current employer contribution rate to each plan is 9.21% of the covered payroll. Employees also contribute a percentage of their payroll. The State Actuary's actuarial valuation for Plan 1 as of June 30, 2012 showed a 69% funded ratio (unfunded liability of $3.8 billion) while Plans 2 and 3 had valuation assets that exceed their accrued liability by $2.3 billion (a 111% funded ratio). The State Actuary's preliminary actuarial valuation for Plan 1 as of June 20, 2013 showed a 63% funded ratio (unfunded liability of $4.831 billion) while Plans 2 and 3 had valuation assets that exceed their accrued liability by $537 million (a 102% funded ratio).

All systems are administered by the Washington State Department of Retirement Systems. Contributions by both employees and employers are based on gross wages. State law requires systematic actuarial funding to finance the retirement plans. Actuarial calculations to determine employer and employee contributions are prepared by the Office of the State Actuary, a nonpartisan legislative agency charged with advising the State Legislature and Governor on pension benefits and funding policy. The current contribution rates of employees and employers for PERS are 9.21% for employers and for employees 6.00% for PERS Plan 1, 4.92% for PERS Plan 2 and vary between 5.0% to 15.0% for PERS Plan 3. In July 2014, the State's Pension

Funding Council adopted contribution rates to be phased in over three biennia, beginning with the 2015-2017 State biennium. For the 2015-2017 State biennium, employer rates for PERS Plans 1, 2 and 3 will be 11% (excluding any administrative fee) and the employee rate for PERS Plan 2 will be 6.12%. These rates are subject to revision by the State legislature. The Office of the State Actuary uses the Projected Unit Credit ("PUC") cost method and the Actuarial Value of Assets ("AVA") to report a plan's funded status. PUC is one of several acceptable measures of a plan's funded status under current GASB rules. The PUC cost method projects future benefits under the plan, using salary growth and other assumptions and applies the service that has been earned as of the valuation date to determine accrued liabilities. AVA is calculated using a methodology which smoothes the effect of short-term volatility in the Market Value of Assets ("MVA") by deferring a portion of annual investment gains or losses over a period of up to eight years.

Pension costs for Energy Northwest employees and post-employment life insurance benefit costs for retirees are calculated and allocated to each Energy Northwest business unit based on direct labor dollars. Energy Northwest's total contribution to PERS in fiscal year 2013 was $15.8 million, most of which was paid by Columbia. It is expected that Energy Northwest's contribution to PERS in fiscal year 2014 will be approximately $12.5 million.

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. Project 1 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.

THE COLUMBIA GENERATING STATION

The Series 2014-C Bonds are being issued for Project 1 and Project 3 and not being issued for Columbia.

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. The lease was extended in 2011 and now is scheduled to terminate on January 1, 2052.

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

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has a maintenance, operating, fuel and capital budget for Columbia of $430 million for the 2015 fiscal year, which ends on June 30, 2015.

The cost of production, using industry standard methodology (such cost calculation methodology includes general, administration and capital costs, but excludes debt service, taxes, depreciation and decommissioning costs), of Columbia electricity is budgeted at $51.08 per megawatt-hour for the 2015 fiscal year. This cost is higher than the $38.49 per megawatt-hour for the 2014 fiscal year because the 2015 fiscal year includes a planned refueling and maintenance outage. Energy Northwest continues to place a high priority on cost-containment.

Columbia had a 45-day planned outage that ended on June 25, 2013. 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. The next planned refueling outage is expected to begin in May 2015.

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.

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.

Recent Developments

During 2013, Columbia moved into the top quartile for industry performance as reported by the Institute of Nuclear Power Operations. Energy Northwest surpassed the safety milestone of 10 million hours with no lost-time injuries. Energy Northwest also broke a consecutive calendar-year generation record (for a refueling outage year) by sending nearly 8.5 million megawatts hours to the grid, and a fiscal year 2014 record by sending the grid 9.8 million megawatt hours.

In 2013, the anti-nuclear-energy group Physicians for Social Responsibility (“PSR”) conducted a grass-roots campaign against Columbia, including filing a petition with the NRC requesting a proceeding to revoke Columbia’s operating license. The NRC denied the petition. PSR has publically opposed Columbia operations since late 2012 when it incorrectly claimed that Columbia’s design was the same as the affected Fukushima plants (as hereinafter described) and that Columbia was susceptible to the same type of natural disasters. PSR issued several press releases and reports purporting to demonstrate that Columbia was uneconomical and should be replaced by cheaper, carbon-producing natural gas; claiming that Columbia was susceptible to earthquake damage, and questioning the NRC about the authenticity of photos Energy Northwest released showing the facility’s robust internal seismic bracing; and releasing a report commissioned from McCullough Research inferring that Columbia should “commence decommissioning at the end of its current refueling cycle in 2015.”

In December 2013, Energy Northwest released a Columbia market assessment commissioned from IHS Cambridge Energy Research Associates (“IHS/CERA”), a firm with 75-years experience as an independent expert in the fields of energy, economics, market conditions and business risk. The IHS/CERA market assessment came to the same conclusion as an April 2013 joint Bonneville-Energy Northwest study: Columbia remains the best value when compared to all practical alternatives for Northwest rate payers.

In January 2014, the region’s Public Power Council (“PPC”), representing Northwest consumer-owned utilities, examined competing market assessments and stated that it found no compelling evidence that ceasing operation of Columbia is economically advisable for the region. During an April 2014 meeting of the Washington Public Utility District Association, the association's executive directed stated, "We trust the PPC and their expert staff analysis," reflecting the position of Energy Northwest's 27 member utilities. The PPC assessment also supports public statements by Bonneville affirming that Columbia provides a unique, firm, baseload, non-carbon emitting generation with predicable costs for the region's rate payers.

Columbia Generating Station's Fiscal Year 2014 Preliminary Financial Results

Energy Northwest's fiscal year 2014 ended on June 30, 2014. The following results are preliminary and subject to independent audit verification. At Columbia during fiscal year 2014 generation totaled nearly 9.8 million megawatt hours (net of station use). Fiscal year 2014 generation was the highest net production of electric power during any single fiscal year in Columbia's history. Operations and maintenance costs were approximately $203 million compared to fiscal year 2013 of approximately $274 million (an outage year) and compared to fiscal year 2012 (the most recent scheduled non-outage year) of approximately $204 million. Capital expenditures totaled approximately $102 million compared to fiscal year 2013 of approximately $62 million. Nuclear fuel related expenses were approximately $61 million. Combined depreciation and decommissioning costs were approximately $91 million. Cost of power generating by Columbia for fiscal year 2014 was $36.96 per megawatt hour.

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 73.6% and has generated 210,058,579 megawatt hours ("MWh") (net of station use) of electric power through June 2014. In the 10-fiscal years ending June 30, 2014, however, the cumulative capacity factor was 85.7%.

Successful implementation of employee performance enhancement initiatives at Columbia has contributed to significant positive results in plant performance. Prior to the record set in 2014, the best generating fiscal year in Columbia's history was in 2006 producing approximately 9.5 million megawatt hours of electric power.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for fiscal years ended June 30, 2012 and 2013 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 2012	FY 2013
Operations, Maintenance and Overhead	$204,344	$274,151
Nuclear Fuel	35,393	42,433
Spent Fuel Disposal Fee	6,560	8,059
Generation Taxes	3,239	4,023
Decommissioning	7,433	6,306
Depreciation and Amortization	74,440	83,967
Investment Income	(407)	(645)
Interest Expense and Discount Amortization	123,936	126,158
Other Expense/(Revenue)	(57,057)[2]	(4,785)
Total Costs	$397,881	$539,667
Net Generation (GWhs)	6,984	8,479

(1) Dollar amounts derived from audited 2012 and 2013 Energy Northwest financial statements.
(2) Due to litigation settlement.

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 2013, Energy Northwest spent $62.1 million on capital improvements at Columbia. Energy Northwest estimates that it spent $102 million in fiscal year 2014 and expects to spend $111 million in fiscal year 2015. The capital improvements at Columbia are expected to include plant and facility modifications, information technology improvements, and replacement of various pieces of equipment. Certain of the costs of these capital improvements in fiscal year 2014 and 2015 were or are expected to be financed by previously issued Columbia Electric Revenue Bonds. Energy Northwest expects to spend between $147.7 million and $57.9 million each fiscal year for the next ten fiscal years for capital improvements at Columbia.

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 or security 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. All performance indicators were also Green. For the First Quarter of 2014, the cornerstones supporting reactor safety had only Green findings and the cornerstones supporting radiation safety had no findings.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary that can be found on the NRS's website (www.nrc.gov). The Safeguards (Physical Protection) cornerstone performance indicators and inspection findings are not integrated into the Action Matrix Summary. The Action Matrix Summary reflects overall plant performance, which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance columns.

Best performing plants are included in the Licensee Response Column where routine (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 14, 2014, the NRC's Regulatory Oversight Process Summary lists 81 plants, including Columbia, in the Licensee Response Column, 11 plants in the Regulatory Response Column, six 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.

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 over 500 operating station peer reviews in 31 countries/areas, including at least once at every member. WANO expects to have a peer review every four years, with a follow-up at the two-year point. WANO completed a peer review of Columbia's performance in November 2012. Initiatives were put in place to improve performance following the peer review. Such initiatives included strengthening decision-making processes, improving enforcement of performance standards, and addressing shortfalls in a number of engineering programs.

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, including Energy Northwest, are INPO members. INPO conducts plant evaluations of all United States plants, including Columbia, approximately every two years. The next peer evaluation of Columbia is scheduled to occur in September 2014.

Coincident with the November 2012 WANO peer review discussed above, INPO conducted a Corporate Evaluation of Energy Northwest. The evaluation concluded that Energy Northwest has taken important steps to improve the effectiveness of governance, oversight, and support for Columbia. It found that recent significant corporate investment to maintain the nuclear facility and the development of a solid relationship with key stakeholders demonstrate a sound commitment to improving the nuclear program. The evaluation did note that two actions needed management attention to anchor and sustain the performance improvement. The first action was to extend the horizon for strategic initiatives and support excellence plans. The second action was to further institutionalize some of the governance and oversight improvement that resulted in the performance improvement. Efforts are in progress in both areas.

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 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 May 1972. The site certification requires Energy Northwest, among other things, to monitor the environmental effects of plant construction and plant operation, comply with standards set for the consumption and discharge of water and for discharges to the air, and develop an effective emergency plan. The State has also issued a National Pollutant Discharge Elimination System ("NPDES") permit and the necessary Certificate of Water Right. The Certificate of Water Right expires when use ceases. The NPDES permit is effective until May 2011 and is renewable for five-year terms thereafter. 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, which is expected in 2014. 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 procured a back-up trailer-mounted diesel pump, with similar capabilities. The U.S. nuclear industry is also establishing Regional Response Centers filled with emergency equipment ready to be supplied to plants such as Columbia in the event of extreme natural events.

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.

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. Item 2 above was replaced with a new order to install a hardened Wetwell containment vent that is severe accident capable.

For the three original orders, all plants were 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. The new fourth order for a hardened Wetwell containment vent requires implementation for Columbia by no later than June 30, 2017. Additionally, periodic status reports must be provided to the NRC so they can monitor progress in implementing the orders. Energy Northwest has responded and provided updates to 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.

Energy Northwest has responded to these information requests relating to seismic and flooding walkdowns, and reevaluations for emergency communications systems and staffing levels. Energy Northwest is currently working with the Department of Energy and Pacific Northwest National Laboratory to perform a seismic hazards analysis using the guidance of the NRC. Energy Northwest expects to perform a ground motion response spectrum analysis by the end of 2015, which will provide the information necessary to evaluate the potential impacts to plant equipment from the revised seismic hazards. Energy Northwest currently is seeking information from the Corps, which is necessary to undertake the flooding hazards analysis.

The NRC examined and assessed Columbia before granting it a 20-year license renewal on May 22, 2012, allowing Columbia to continue operations through 2043.

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, and to ensure an adequate and secure supply of fuel, to minimize exposure to fluctuations in market prices and to procure the fuel at a significant savings. Energy Northwest issued bonds in August 2012 to finance a portion of the cost of the Program. Under the Program, the U.S. Department of Energy ("DOE") provided approximately 9,082 metric tons of depleted uranium hexafluoride ("Uranium Tailings") at no cost to Energy Northwest. The Uranium Tailings were physically transferred from DOE ownership to Energy Northwest ownership at the Paducah Gaseous Diffusion Plant ("PGDP") in Paducah, Kentucky, where the Uranium Tailings were enriched to a level necessary for fabrication into commercial nuclear fuel (the Uranium Tailings as so enriched, the "Enriched Uranium").

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 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.

Nuclear Fuel

The supply of nuclear fuel assemblies requires four basic activities prior to insertion of the fuel assemblies into a nuclear reactor. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and conversion of the Enriched Uranium to uranium oxide pellets which are fabricated into finished fuel assemblies.

Fabrication services for the 2009 through 2017 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 approved the Program. The Program is expected to provide enough natural uranium to meet Columbia's requirements through 2028.

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 has paid a quarterly fee based on about one dollar per megawatt-hour of net electricity generated and sold from Columbia, however, the District of Columbia Court of Appeals ruled that the DOE had no grounds to collect the waste fees unless the Yucca Mountain project was restarted or Congress passed an alternative disposal plan. DOE ceased collecting the disposal fee from Energy Northwest effective May 16, 2014. 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's Independent Spent Fuel Storage Installation ("ISFSI") at the Columbia Generating Station is a temporary dry cask storage facility intended to store spent nuclear reactor fuel in NRC approved dry storage casks until the DOE completes its plan for a national repository. Currently the ISFSI consists of two concrete pads storing a total of 36 casks. In order to accommodate spent fuel to be generated through the end of the plant's operating license period (2044), Energy Northwest is planning the ISFSI facility expansion to store an additional 96 casks. The ISFSI expansion project will provide the additional storage capacity by constructing three additional pads with a capacity of 32 casks each. Energy Northwest previously financed a portion of the costs needed for the construction of the existing ISFSI pads.

No additional issues are anticipated with the ISFSI expansion project. However, the NRC is in the process of developing additional security rulemaking which may potentially impose additional requirements beyond currently planned security controls. The extent of those additional requirements or when they will be imposed to Columbia are not known at this time but are not anticipated to come into place within the next two or three years.

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Annual payments to a fund established pursuant to this plan began in 2003 and are held by Energy Northwest. These payments will occur annually through 2044. Cash payments for decommissioning and site restoration will begin in 2045 with expected equal installments for five years totaling $10.6 million in 2014 dollars. The fair market value of the cash and investments in this fund were $1.2 million as of June 30, 2014.

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 $459 million (in 2013 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 $109 million (in 2013 dollars).

The current decommissioning funding plan requires annual deposits to a fund through fiscal year 2043, the end of Columbia's current operating license with the NRC. The plan assumes that such deposits will grow at a 2% real rate of return and that Columbia will be placed in an approximately 60-year safe storage until 2105, 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, 2013, totaled approximately $188.6 million. A separate fund has been established for site restoration. The balance of this fund as of June 30, 2013, totaled approximately $31.3 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. Claims relating to Project 1, Project 3 or Columbia that are not covered by insurance are paid from revenues under the related Project Net Billing Agreements.

Nuclear insurance includes liability coverage, property damage, decontamination and premature decommissioning coverage and accidental outage and/or extra expense coverage. The liability coverage is governed by the Price-Anderson Act, while the property damage, decontamination and premature decommissioning coverage are defined by the Code of Federal Regulations. Energy Northwest continues to maintain all regulatory required limits as defined by the NRC, Code of Federal Regulations and the Price-Anderson Act. The NRC requires Energy Northwest to certify nuclear insurance limits on an annual basis. Energy Northwest intends to maintain insurance against nuclear risks to the extent such insurance is available on reasonable terms and in an amount and form consistent with customary practice. Energy Northwest is self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered under policy exclusions, terms or limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Such losses could have an effect on Energy Northwest's results of operations and cash flows.

The Price-Anderson Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Price-Anderson Act sets the statutory limit of public liability for a single nuclear incident at $13.2 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection ("SFP"). Energy Northwest has $375 million of liability insurance as the first payer of protection. If any U.S. nuclear generation plant has a significant event that exceeds the plant's first layer of protection, every operating licensed reactor in the U.S. is subject to an assessment up to $127.3 million plus state insurance premium tax. Assessments are limited to $18.96 million per reactor, per year, per incident, excluding taxes. The SFP is adjusted at least every five years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1.06 billion nuclear decontamination and property damage insurance and required the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Energy Northwest has aggregate coverage in the amount of $2.25 billion, which is subject to a $5 million deductible per accident.

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 submitted an application requesting a new 50-year license 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 annually for continued operations, until a formal decision is issued by FERC and a new operating license is granted.

In fiscal year 2013, production at Packwood totaled 103,700 net MWhs, down 13% from the previous year primarily due to less precipitation and lower snowfall levels in the Cascade Mountains. Packwood's average availability during the last 12 years has been 97.7%, and has produced 4,597,249 MWh since commercial operation began. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs. 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.

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 7.91 cents per kilowatt hour during fiscal year 2013.

In fiscal year 2013, Nine Canyon produced 228,230 net megawatt-hours of electricity compared to 261,630 net megawatt-hours in fiscal year 2012.

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 SERVICES AND DEVELOPMENT

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 supports the local economy and Department of Energy by offering facilities for lease to early stage businesses, the Pacific Northwest National Laboratory and Hanford contractors.

Energy Northwest has done a preliminary feasibility study on NuScale Power's small modular reactor initiative, which has received U.S. DOE funding.

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:

Energy Northwest v. SPX Heat Transfer Inc., (CV13-5151-SAB). Energy Northwest filed suit against SPX Heat Transfer Inc. ("SPX") on December 24, 2013 seeking the recovery of damages relating to SPX's breach of contract and amended the lawsuit on March 18, 2014. In February, 2009, SPX's predecessor in interest Yuba Heat Transfer LLC and Energy Northwest entered into a contract for the design, engineering, fabrication and delivery of the condenser modules and related components for Columbia. In the lawsuit, Energy Northwest contends that SPX breached the contract (1) by failing to meet contract specifications for condenser backpressure and sub-cooling; (2) by failing to provide work that was free from defect in design and fabrication; and (3) by failing to meet the express warranties contained in the contract. No specific amount of damages has been demanded in the complaint. SPX has responded to the lawsuit and has included a counterclaim for damages. In its counterclaim, SPX seeks the balance of the contract amount, which is $2,070,334 plus accumulated interest. Additionally, SPX seeks recovery of some or all of a portion of the incentive fee contained in the contract as determined by the formula in the contract with no specific amount demanded. Energy Northwest has denied that it owes SPX the contract balance or any amount of the performance incentive. On July 22, 2014, Energy Northwest made an offer of settlement to SPX in accordance with RCW 39.04.240 and 4.84.260 and the Federal Rules of Civil Procedure, Rule 68. In the offer of settlement, Energy Northwest agreed to accept a judgment from SPX for all claims including but not limited to SPX's counterclaims, for $0.00. Should SPX decline this offer of settlement and Energy Northwest prevail at trial with a jury verdict greater than the offer of settlement, in addition to the jury verdict SPX would be obligated to pay Energy Northwest its legal costs and attorneys' fees from the date of the offer of settlement. The outcome of this matter cannot be predicted at this time.

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. On March 11, 2014, the court awarded Energy Northwest summary judgment in the amount of $19.3 million for costs incurred to continue to operate and maintain its dry storage program. This favorable decision ultimately led to the approval by the Executive Board of a settlement agreement with the Government in the amount of $23.6 million to dispose of the second action. The settlement agreement also provides for a claims process to obtain payment for continuing damages between July 1, 2012, through December 31, 2016, which obviates the need for litigation to recover damages for this time period. The settlement agreement is expected to be fully executed by the parties by fall 2014. Energy Northwest received $48.7 million in 2011 under the first action that resulted in a Stipulation for Entry of Final Judgment in Favor of Plaintiff Energy Northwest.

LEGAL MATTERS

The approving opinions of Foster Pepper PLLC, Bond Counsel to Energy Northwest, as to the legality of the Series 2014-C Bonds will be in substantially the form appended hereto in Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2014-C BONDS." The opinions of Orrick, Herrington & Sutcliffe LLP, Special Tax

Counsel, as to the status of the interest on the Series 2014-C Bonds for federal income tax purposes will be in substantially the forms appended hereto in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2014-C 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 opinions of Bond Counsel is appended hereto in Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2014-C 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 and Project 3, will be passed upon for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski LLP, New York, New York, a member of Norton Rose Fulbright, Counsel to the Underwriters.

TAX MATTERS

At closing of the Series 2014-C 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 2014-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). Special Tax Counsel also is expected to deliver its opinion that interest on the Series 2014-C 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 2014-C 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 2014-C Bonds and the due authorization and issuance of the Series 2014-C 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 2014-C BONDS."

To the extent the issue price of any maturity of the Series 2014-C Bonds is less than the amount to be paid at maturity of such Series 2014-C Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2014-C 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 2014-C Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Series 2014-C Bonds is the first price at which a substantial amount of such maturity of the Series 2014-C Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the Series 2014-C Bonds accrues daily over the term to maturity of such Series 2014-C 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 2014-C Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2014-C Bonds. Beneficial Owners of the Series 2014-C Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2014-C Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series

2014-C Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2014-C Bonds is sold to the public.

Series 2014-C Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a 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 1954 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 2014-C 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 2014-C Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2014-C Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2014-C 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 2014-C Bonds may adversely affect the value of, or the tax status of interest on, the Series 2014-C 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 2014-C Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of amounts treated as interest on, the Series 2014-C 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 1954 Code or court decisions may cause interest on the Series 2014-C 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. For example, Representative Dave Camp, Chair of the House Ways and Means Committee has released draft legislation that would subject interest on the Series 2014-C Bonds to federal income tax at an effective rate of 10% or more for individuals, trusts and estates in the highest tax bracket, and the Obama Administration has proposed legislation that would limit the exclusion from gross income of interest on the Series 2014-C Bonds to some extent for high-income individuals. The introduction or enactment of any such legislative proposals or clarification of the 1986 Act or the 1954 Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the Series 2014-C Bonds. Prospective purchasers of the Series 2014-C 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 2014-C 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 1954 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 1954 Code.

Special Tax Counsel's engagement with respect to the Series 2014-C Bonds will end with the issuance of the Series 2014-C 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 2014-C Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than Energy Northwest, Bonneville and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which Energy Northwest or Bonneville legitimately disagrees may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2014-C Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2014-C Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's, a Standard & Poor's Financial Services LLC business ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2014-C 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 2014-C 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 2014-C Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the Series 2014-C Bonds from Energy Northwest and to make a bona fide public offering of such Series 2014-C 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 2014-C Bonds is $1,018,087. The Underwriters' obligations under each contract of purchase are subject to certain conditions precedent contained in such contract of purchase. The Underwriters will be obligated to purchase all of the Series 2014-C Bonds being sold under the contract of purchase for the Series 2014-C Bonds if any of the Series 2014-C Bonds are purchased.

The Series 2014-C Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such Series 2014-C 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 2014-C Bonds.

J.P. Morgan Securities LLC ("JPMS"), an Underwriter of the Series 2014-C Bonds, has informed Energy Northwest that it has entered into a negotiated dealer agreement (the "Dealer Agreement") with Charles Schwab & Co., Inc. ("CS&Co.") for the retail distribution of certain securities offerings, including the Series 2014-C Bonds, at the original issue prices. Pursuant to the Dealer Agreement, (if applicable to this transaction), CS&Co. will purchase the Series 2014-C Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any Series 2014-C Bonds that CS&Co. sells.

Citigroup Global Markets Inc., an underwriter of the Series 2014-C Bonds, has informed Energy Northwest that it has entered into a retail distribution agreement with each of TMC Bonds L.L.C. ("TMC") and UBS Financial Services Inc. ("UBSFS"). Under these distribution agreements, Citigroup Global Markets Inc. may distribute municipal securities to retail investors through the financial advisor network of UBSFS and the electronic primary offering platform of TMC. As part of this arrangement, Citigroup Global Markets Inc. may compensate TMC (and TMC may compensate its electronic platform member firms) and UBSFS for their selling efforts with respect to the Series 2014-C 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.

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 Continuing Disclosure Agreements, to be dated the date of delivery of the Series 2014-C Bonds, for the benefit of the owners and beneficial owners of the Series 2014-C 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 2014-C 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, 2014. 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, 2014. 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 previously entered into continuing disclosure undertakings under Rule 15c2-12. With respect to previous undertakings for the Net Billed Bonds, Energy Northwest has filed its annual financial information and operating data in a timely manner. It was discovered, however, that Energy Northwest filed some, but not all, bond rating changes resulting from insurance downgrades for certain bonds that are no longer outstanding. In addition, 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. 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 did not include 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 AGREEMENTS."

INITIATIVE AND REFERENDUM

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

BANKRUPTCY

A municipality such as Energy Northwest must be specifically authorized under state law in order to seek relief under Chapter 9 of the U.S. Bankruptcy Code (the "Bankruptcy Code"). Chapter 39.64 RCW, entitled the "Taxing Relief Bankruptcy Act," permits any "taxing district" (defined to include any municipality or political subdivision, such as Energy Northwest) to voluntarily petition for relief under the Bankruptcy Code. A creditor cannot bring an involuntary bankruptcy proceeding against a municipality. Under Chapter 9, a federal bankruptcy court may not appoint a receiver for a municipality or order the dissolution or liquidation of the municipality. The federal bankruptcy courts have some discretionary powers under the Bankruptcy Code.

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 2014-C Bonds, the basic agreements securing the Series 2014-C 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 Prior Lien Resolutions and Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the Series 2014-C Bonds is to be construed as a contract with the holders of such Series 2014-C 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.

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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TABLE OF CONTENTS

PAGE

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 5, 2014, furnished by the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2014-C and Project 3 Electric Revenue Refunding Bonds, Series 2014-C (collectively, the "2014-C Bonds"). (Energy Northwest's Project 1, Project 3, and Columbia Generating Station are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as the "Net Billed Projects".) Such information in this Appendix A 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 2014-C 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.

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

GENERAL

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

Bonneville's primary enabling legislation includes the following federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 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 2014 of approximately 10,611 annual average megawatts (defined below) under median water conditions and approximately 8,506 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 and/or possesses, 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 approximately 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."

Proportionately, Preference Customers are the largest customer group to whom Bonneville sells power. For example, Bonneville estimated in Fiscal Year 2013 that on a planning basis in Operating Year 2014, it would meet 8,191 annual average megawatts of loads, of which approximately 84 percent would be Preference Customer loads. By contrast Bonneville estimated approximately seven percent would be federal agency loads and DSI loads, and approximately nine percent would be exports and other intra-Regional contract obligations. (Actual energy amounts may differ from planned amounts because of energy usage variations due to the weather, end-user behavior, economic activity and other factors.)

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 conformance with certain national regulatory initiatives to promote competition in wholesale power markets, Bonneville has 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 Services operations and Power Services operations, 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 makes 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 $692 million (including $225 million in principal payments in advance of due dates) in full and on time for Bonneville's fiscal year ended September 30, 2013 ("Fiscal Year 2013"). Bonneville has made all payments to the United States Treasury in full and on time since 1984.

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 descriptions of the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements. For an additional description of the Direct Pay Agreements, 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" and see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

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.

Regional Power Sales and Rates Background

Bonneville's current power sales agreements with Preference Customers are in effect through Fiscal Year 2028 ("Long-Term Preference Contracts"). Virtually all such agreements were executed in 2008 and relate to power sales from Fiscal Year 2012 through Fiscal Year 2028. Under these contracts, Bonneville provides various electric power products 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. 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 and Power Products." Bonneville also sells 312 average annual megawatts of power under separate direct service commitments to two DSIs through calendar year 2022. Of this amount, 300 annual average megawatts are sold to Alcoa, Inc. ("Alcoa"), an aluminum industry DSI.

Bonneville sells electric power for Regional load requirements at rates that are established to recover Bonneville's cost of providing such service. Bonneville sells power to Preference Customers and federal agencies, in each case for their requirements, at periodically established "Priority Firm Preference Rates" (or "PF Preference Rates") that are proposed in advance of the delivery of the power. The PF Preference Rate class 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 providing such services. Beginning in Fiscal Year 2012, PF Preference Rates have been and will be, established, at least through the term of the Long-Term Preference Contracts, on the basis of "Tiered Rates," as discussed below. For a discussion of Bonneville's currently applicable power rates, see "CERTAIN

DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rate Developments," and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2014-2015." The rate for the power Bonneville sells to DSIs is the Industrial Firm Power Rate ("IP Rate"), which is based on the PF Preference Rate and certain adjustments required by federal law.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Bonneville Power and Transmission Rates Developments

To establish rates of general applicability for electric power and for transmission and related services, after concluding formal administrative processes, in July 2013, Bonneville filed final proposed power and transmission rates for Fiscal Years 2014 and 2015 (the "2014-2015 Rate Period") with FERC for its review. FERC granted interim approval of such rates (the "Final 2014-2015 Rate Proposal") in September 2013, and granted final approval for transmission rates and for power rates in the spring of 2014. The rates as approved by FERC are referred to herein as the Final 2014-2015 Rates. Upon final FERC review, the rates may be challenged in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which has original jurisdiction over many Bonneville actions.

Consistent with longstanding policy, Bonneville's Final 2014-2015 Rate Proposal was prepared with the goal of assuring at least a 95 percent probability over the two-year rate period that Bonneville will make its scheduled payments to the United States Treasury on time and in full ("Treasury Payment Probability" or "TPP"). Bonneville's United States Treasury payments are payable after Bonneville's non-federal payment and net billing obligations, including amounts, if any, under the Net Billing Agreements, are met. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met." The Final 2014-2015 Rate Proposal increased both power and transmission rates over rates in the immediately preceding two-year rate period (the "2012-2013 Rate Period"). Average PF Preference Rates (excluding "Tier 2 PF Rates," which Bonneville charges to meet a small amount of incremental loads, as discussed herein) increased by nine percent, to $31.50 per megawatt hour; the IP Rate increased by 7.3 percent, to $38.97 per megawatt hour; and, average Transmission Services rates increased by about 11 percent. For a discussion of Tier 2 PF Rates, 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."

Some important factors leading to the increase in power rates were expectations of lower revenue from the sales of surplus (secondary) energy, increased costs to operate and maintain the hydroelectric facilities of the Federal System, and increased funding levels under existing long-term agreements for the Federal System fish and wildlife program. A number of factors have led to increased spending by Bonneville for Transmission Services, and to the increase in transmission and related rates. Construction of new lines and replacements to maintain reliability and facilitate the integration of renewable resources, such as wind, accounts for a large portion of the transmission rate increase. Increased compliance requirements and additional cyber and physical security requirements and other operational and maintenance expenses also contributed to the transmission rate increase.

With regard to power rates, the Final 2014-2015 Rates include a rate level adjustment mechanism (the "Cost Recovery Adjustment Clause" or "CRAC") that allows PF Preference Rates and the IP Rate levels to be increased at the beginning of each fiscal year of the rate period, according to certain financial metrics. The CRAC would enable Bonneville to obtain up to $300 million in each year of the rate period in additional revenues, depending on a variety of factors. The CRAC did not trigger for Fiscal Year 2014. As of July 23, 2014, Bonneville projected that there was less than 0.1 percent chance that the CRAC will trigger for Fiscal Year 2015. For more detail on the risk mitigation tools for power rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2014-2015." See "TRANSMISSION SERVICES—General - Bonneville's Transmission and Ancillary and Control Area Services Rates."

Bonneville began conducting workshops in the spring of 2014 related to developing rates for power and for transmission and related services for Fiscal Years 2016 and 2017 ("2016-2017 Rate Period"). Bonneville plans to begin the formal rate proceeding in November 2014 and submit the final rate proposal to FERC by the end of July 2015. Bonneville has informed its customers and others that internal preliminary analysis indicates that its power rates in such period could increase by approximately six percent and that its transmission and related rates in such period could increase by approximately nine percent, in each case over the average rates now in effect.

The upward rate pressure on power rates arises from increased debt service associated with past capital spending and debt restructuring, and to a lesser degree, from: steadily increasing program expenses reflecting the continuation of O&M and non-routine extraordinary maintenance associated with aging Federal System infrastructure and efforts to meet protection and mitigation commitments for fish affected by the operation of the Federal System, and from continuing diminished expectations of low net seasonal surplus (secondary) power sales revenues caused by lower market prices due in part to increased supplies of low priced energy from other suppliers.

The upward rate pressure on transmission rates arises primarily from increased debt service associated with past and anticipated capital spending for replacement of aging Federal System infrastructure and for new infrastructure associated with (i) increased transmission usage and demands, and (ii) increased system reliability and security requirements.

Fiscal Year 2014 Expectations

Analyses as of July 8, 2014, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2014 water supply for the Columbia River basin will be approximately 107 percent of the 30-year historical average, as measured in terms of millions of acre feet of water (or "MAF") runoff at The Dalles Dam. Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and southern British Columbia. Runoff is a key determinant of the timing of hydroelectric power Bonneville has to meet its long-term power sales and related obligations and the amounts and timing of seasonal surplus (secondary) energy that Bonneville has to market.

Based on information as of June 30, 2014, Bonneville forecast that Adjusted Net Revenues will be $289 million in Fiscal Year 2014. ("Adjusted Net Revenues" is a metric which is not in accordance with accounting principles generally accepted in the United States ("Generally Accepted Accounting Principles" or "GAAP")) that Bonneville uses to measure financial results independent of certain debt financing actions with respect to Debt Optimization and is described in "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2013—Bonneville's Use of Adjusted Net Revenues as a Financial Performance Metric.") Debt Optimization is described in "—Regional Cooperation Debt." The foregoing estimates are based on unaudited operating results through June 30, 2014 and forecasts for the remainder of the current fiscal year. These forecasts are improved from prior Fiscal Year 2014 quarterly forecasts of fiscal-year-end results and reflect, for Power Services, improved hydroelectric generation conditions and lower than previously expected expenses, and for Transmission Services, greater than expected revenues arising from favorable hydro conditions and lower than expected expenses. For the remainder of Fiscal Year 2014, Bonneville expects steady electricity prices and stable hydro conditions. By contrast in establishing the Final 2014-2015 Rates, Bonneville forecast that for Fiscal Year 2014, Adjusted Net Revenues would be $138 million.

Bonneville is now employing a new non-GAAP financial metric for Power Services financial operations for determining Adjusted Net Revenues. This new metric (referred to as "Power Modified Net Revenues" or "PMNR"), seeks to eliminate the non-operating effects on Power Services of debt management actions with respect to the issuance of the 2014-C Bonds under regional cooperation debt. See "—Regional Cooperation Debt." (By contrast, the non-operating effects on Power Services and Transmission Services of actions from prior debt management actions with respect to Debt Optimization are reflected at the Bonneville-wide level in the formulation of Adjusted Net Revenues). Bonneville management believes that PMNR is a better representation of Power Services operating results than net revenues. Based on information as of June 30, 2014, Bonneville forecast that Power Services' PMNR will be $138 million in Fiscal Year 2014.

For net revenues (which is a GAAP metric), based on information as of June 30, 2014, Bonneville forecast that Power Services' net revenues will be $459 million in Fiscal Year 2014. This forecast amount includes about $321 million in non-operating effects on Power Services from the debt management actions related to the 2014-C Bonds as described in the discussion of PMNR immediately above. By contrast, in establishing the Final 2014-2015 Rates, Bonneville forecast that for Fiscal Year 2014, Power Services' net revenues would be $9 million. As of June 30, 2014, Bonneville forecast that Transmission Services' net revenues will be $150 million in Fiscal Year 2014. By contrast, in establishing the Final 2014-2015 Rates, Bonneville forecast that for Fiscal Year 2014, Transmission Services' net revenues would be $129 million.

As of June 30, 2014, Bonneville estimated that Total Financial Reserves will be approximately $1.14 billion at the end of Fiscal Year 2014 as compared to $1.27 billion as of the end of Fiscal Year 2013. "Total Financial Reserves" is a non-GAAP and unaudited metric that Bonneville uses to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Reserves." As of June 30, 2014, Bonneville estimated that aggregate Reserves Available for Risk, or "RAR," will be $720 million. RAR is a non-GAAP and unaudited metric that Bonneville uses in ratemaking to reflect the amount of reliably available financial resources that Bonneville can use to meet or to fund unplanned or unexpected payment obligations or to cover unplanned or unexpected reductions in revenue. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Reserves." Of that aggregate amount of RAR, approximately $263 million is forecast RAR for Power Services and approximately $457 million is forecast RAR for Transmission Services.

All of the Total Financial Reserves in the Bonneville Fund are available to meet all of Bonneville's costs without regard to whether they were derived from Transmission Services' operations or Power Services' operations and without regard to Bonneville's aggregate RAR or the business lines' respective RAR levels. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Based on Total Financial Reserve levels in the Bonneville Fund, and forecasts of revenues and expenses as of the end of the third quarter of Fiscal Year 2014 and more recent internal updates, Bonneville believes that it will meet its Fiscal Year 2014 United States Treasury payment responsibility on time and in full. The foregoing forecasts of fiscal year-end Total Financial Reserves, RAR, and Adjusted Net Revenues are based on highly uncertain variables and are subject to change.

Regional Cooperation Debt

On June 26, 2014, the Energy Northwest Executive Board adopted a motion supporting the issuance of the 2014-C Bonds to increase the weighted average maturities of outstanding Project 1 and Project 3 bonds to match more closely the originally expected useful lives of Project 1 and Project 3. The refinancing of certain Project 1 and Project 3 bonds which matured on July 1, 2014, with later maturing Project 1 and Project 3 2014-C Bonds will make available Bonneville revenues in the current year, thereby enabling Bonneville to advance the repayment of a like amount of certain of Bonneville's repayment obligations to the United States Treasury. More particularly, Bonneville will prepay a portion of its repayment obligations with respect to amounts appropriated by Congress for federally-owned hydroelectric facilities of the Federal System. These federal repayment obligations bear interest at a rate that is higher than the rates of interest on the 2014-C Bonds.

Bonneville has asked Energy Northwest to consider issuing similar refunding bonds in the future for Project 1, Project 3 and the Columbia Generating Station. The Energy Northwest Executive Board is considering this request, which is known as the regional cooperation debt proposal. As with the 2014-C Bonds, these proposed refinancing efforts would make available Bonneville revenues in future years, thereby enabling Bonneville to prepay certain of Bonneville's United States Treasury repayment obligations. With respect to the issuance of Columbia Generating Station refunding bonds, the restructuring may involve freeing up Bonneville revenues to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury in addition to the prepayment of a portion of the appropriated Federal investment in the power facilities of the Federal System. On June 26, 2014, the Energy Northwest Executive Board also adopted a motion supporting the issuance of up to $6 million in Columbia Generating Station refunding bonds in 2016 and 2017 to increase the weighted average maturities of certain outstanding Columbia Generating Station bonds to match more closely the originally expected useful lives of facilities refinanced by those proposed Columbia Generating Station refunding bonds.

In the past, Energy Northwest and Bonneville have worked together to refinance certain maturities of Project 1, Project 3 and Columbia Generating Station bonds with series of refunding bonds having later maturities so that the weighted average maturities of outstanding Project 1, Project 3 and Columbia Generating Station bonds more closely matched the originally expected useful lives of the refinanced Project 1, Project 3 and Columbia Generating Station facilities, respectively. Between 2001 and 2009, these refundings were known as the Debt Optimization Program. By extending maturities of outstanding bonds, these refundings made available Bonneville revenues which were then used to prepay a portion of Bonneville's federal appropriations repayment obligations and to pay down the outstanding balance of the then-outstanding bonds issued by Bonneville to the United States Treasury, thereby increasing the borrowing capacity available to Bonneville under its authority to borrow from the United

States Treasury. The regional cooperation debt proposal is similar in certain respects to these prior transactions. See the Official Statement under "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS."

Bonneville manages its overall debt portfolio to meet the objectives of (1) minimizing the cost of federal and non-federal 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 "BONNEVILLE FINANCIAL OPERATIONS."

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 approximately $2.4 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 75 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 2013.

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 annual 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 2014 (August 1, 2013 through July 31, 2014), the total Federal System would be capable of producing approximately 8,506 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes approximately 6,909 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,112 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including co-generation, renewable, and non-utility generation projects), and approximately 484 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 2014."

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 2014 is estimated to be approximately 83 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 2014."

The amount and timing 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. See "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."

Bonneville markets almost all 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 2014, the Federal System is estimated to generate seasonal surplus (secondary) energy of 1,575 annual average megawatts, assuming average water conditions (median water flows) (current expectations are for near average water conditions in Operating Year 2014). In years with high water conditions (high water flows) the amount of seasonal surplus (secondary) energy could be as much as 2,659 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 included in the Federal System. See Footnote 10 in the following table "Operating Federal System Projects for Operating Year 2014." 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 approximately 484 annual average megawatts in Operating Year 2014.

Operating Federal System Projects for Operating Year 2014

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 an 80-year record of river flows based on the period from 1929-2008 for planning purposes. During this period, low water conditions ("Low Water Flows") occurred in 1936-1937, median water conditions ("Median Water Flows") occurred in 1957-1958, and high water conditions ("High Water Flows") occurred in 1973-1974. 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 2014, the Federal System January 120-Hour peaking 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 2014[1]

Project	Initial Service Year	Number of Units	January Capacity (120-Hour 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 including Pump Turbine	1941	33	4,994	2,601	2,408	1,982
Hungry Horse	1952	4	319	140	97	76
Other Reclamation Projects[6]		16	32	168	150	119
1. Total Reclamation Projects		53	5,345	2,909	2,655	2,177
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,374	1,440	1,349	1,139
John Day	1968	16	2,295	1,387	1,077	815
The Dalles w/o Fishway[7]	1957	24	1,830	1,027	826	609
Bonneville	1938	20	921	568	559	403
McNary	1953	14	1,036	703	639	485
Lower Granite	1975	6	737	391	284	175
Lower Monumental	1969	6	810	465	319	182
Little Goose	1970	6	859	415	295	179
Ice Harbor	1961	6	586	318	253	158
Libby	1975	5	483	276	229	186
Dworshak	1974	3	434	282	217	145
Other Corps Projects[8]		20	207	282	259	217
2. Total Corps Projects		153	12,572	7,554	6,306	4,693
3. Idle Federal Capacity[9]			(8,043)	0	0	0
4. Total Reclamation and Corps Projects (line 1 + line 2 + line 3)		**206**	**9,874**	**10,463**	**8,961**	**6,870**
Non-Federally-Owned Projects						
Columbia Generating Station[10]	1984	1	1,130	1,030	1,030	1,030
Other Non-Federal Hydro Projects[11]		7	32	60	44	40
Other Non-Federal Projects[12]		11	29	82	82	82
5. Total Non-Federally-Owned Projects		**19**	**1,191**	**1,172**	**1,156**	**1,152**
Federal Contract Purchases						
6. Total Bonneville Contract Purchases[13]		**n/a**	**893**	**501**	**494**	**484**
Total Federal System Resources						
7. Total Federal System Resources (line 4 + line 5 + line 6)		**225**	**11,958**	**12,136**	**10,611**	**8,506**

Source: 2013 Pacific Northwest Loads and Resources Study, Bonneville, October 2013.

(1) Operating Year 2014 is August 1, 2013 through July 31, 2014. Any discrepancies in totals for figures portrayed in this table and the "2013 Pacific Northwest Loads and Resources Study" are due to rounding.

(2) January Capacity is megawatts of capacity ("MW") and is measured by Bonneville as "January 120-Hour Peak MW Capacity," which is the maximum generation to be produced under Low Water Flows in 20 six-hour periods (five days a week, for four weeks) assuming a base case of high loads as experienced

historically in the month of January. January is a benchmark month for the Federal System peaking capacity because of the potential for high peak loads during January due to cold winter weather. These January estimates are further reduced by Bonneville for estimated hydro maintenance and estimates of idle Federal System hydro capacity. See footnotes (3) and (9), below.

(3) Maximum energy capability is the estimated amount of hydroelectric energy to be produced using High Water Flows for energy in annual average megawatts ("aMW"). 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 2013 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 aMW.

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

(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) 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.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954), and Lost Creek (1975). Some of these projects have less January capacity than annual energy due to the fact that they do not operate in January.

(9) The Federal System hydroelectric projects have more machine capacity from the generating units than fuel (river flows) available to operate all units on a continuous basis. Idle Federal Capacity is the amount by which the machine capacity exceeds the estimated capacity that would be available given the fuel availability (river flows) in a typical January.

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station is expected to provide approximately 878 annual average megawatts in most refueling years and 1,030 annual average megawatts in non-refueling years. Columbia Generating Station is not scheduled for refueling in Operating Year 2014 and, therefore, will provide approximately 1,030 annual average megawatts. Actual generation during an operating year 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."

(11) Other Non-Federal Hydro Projects include project capability from 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 project output from 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. 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 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 (including, among other sources, electricity supplied by natural-gas fired generators, wind generators, and other non-Federal System hydroelectric generators) 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."

Regional 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 directly to two DSIs in the aggregate amount of approximately 312 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 which 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."

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

Bonneville has a large number of parties with which 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. There is ongoing litigation among Bonneville and parties from the Pacific Southwest arising out of the 1999-2001 West Coast power crisis. See "BONNEVILLE LITIGATION—Litigation and Related Administrative Disputes in Connection with the West Coast Power Crisis in 1999-2001."

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 a counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. Despite mitigation efforts, however, 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.

Largest Power Services' Customers

The following table lists Power Services' top ten largest customers in terms of their percentage contribution to Power Services' overall sales revenue in Fiscal Year 2013. The table also reflects the applicable customer class of the related customer.

Bonneville Power Services' Ten Largest Customers By Sales[1]
(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2013)

Customer Name (Class)	Approximate % of Sales
Snohomish County PUD No. 1 (Preference)	9%
Cowlitz County PUD No. 1 (Preference)	6%
City of Seattle, City Light Dep't. (Preference)	6%
Pacific Northwest Generating Cooperative (Preference)	5%
Tacoma Power (Preference)	5%
ALCOA, Inc. (DSI)	4%
Clark Public Utilities (Preference)	4%
Powerex Corp. (Independent Power Producer)	3%
Eugene Water & Electric Board (Preference)	3%
Morgan Stanley Capital Group, Inc. (Power Marketer)	3%

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(1) Excludes inter-business line transactions between Power Services and Transmission Services. In support of its power marketing activities, Power Services obtains large amounts of transmission and related service from Transmission Services.

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. Bonneville refers to these loads as "net requirements." 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 included in the Long-Term Preference Contracts. The Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load ("Tier 2 Loads") on Bonneville above a baseline level of loads ("Tier 1 Loads") reflective of loads placed on Bonneville prior to the commencement of power sales under Long-Term Preference Contracts.

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 and Power Products. Bonneville currently provides two basic types of power service under the Long-Term Preference Contracts: (i) Slice/Block service, which is an integrated power product combining Slice of the System (or "Slice") and Block power, and (ii) Load Following service. Under Slice/Block, Bonneville commits to provide a Slice product under which the purchaser receives a proportionate share of the actual output of the Federal System as generated and fixed amounts of power at designated times ("Block"). Under Load Following service, Bonneville provides the actual power requirements of the related customer ("Full Requirements" product).

Sixteen separate Preference Customers purchase on a Slice/Block basis. The remaining Preference Customers (over 100) take Load Following service. In aggregate, sales of the Slice portion of Slice/Block represent approximately 26.7 percent of Federal System generation. Preliminary forecasts for Fiscal Year 2014 indicate that loads met under Load Following products will be approximately 3,300 annual average megawatts. Loads met by Slice/Block will be approximately 3,800 annual average megawatts in total, half of which is expected to be for the Block portion (and half of which is expected to be for the Slice portion). 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.

Bonneville provides all of the foregoing power products at PF Preference Rates, although the particular rate features, levels and determinants vary depending on the power product. All of the Long-Term Preference Contracts subject the customers to a payment commitment under which they are required to pay for power tendered by Bonneville. For Slice, the customers pay a fixed percentage of the costs the Federal System generation without regard to the amount of power actually generated. In either case, 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.

Tiered Rates for Long-Term Preference Contracts. Prior to Fiscal Year 2012, when Bonneville augmented Federal System resources with market purchases or other generating resources, the costs of these typically more expensive purchases were, in general, 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. Under the Long-Term Preference Contracts, Bonneville employs PF Preference Rates that are "tiered" so that power that Bonneville sells to meet the incremental Preference Customer loads above a baseline level of loads is provided at rates that directly and exclusively recover the associated costs that Bonneville bears in meeting such incremental loads. The Long-Term Preference Contracts involve two tiers of power rates, which Bonneville expects to establish biennially in all but the final three years of Long-Term Preference Contracts: "Tier 1 PF Rates" and "Tier 2 PF Rates."

Tier 1 PF Loads and Tier 1 PF Rates. Preference Customers purchase a limited amount of power at Tier 1 PF Rates, which rates in general reflect the historically imbedded costs of power from the Federal System. A customer's right to purchase power at Tier 1 PF Rates is capped in general at an amount equal to the net requirement loads it placed on Bonneville in Operating Year 2010 (with certain possible adjustments) ("Tier 1 Loads"), thus, the aggregate amount of power that can be purchased at Tier 1 PF Rates in general reflects the generating output of the Federal System in Fiscal Year 2010 (updated with each rate period to reflect changed Federal System generation expectations).

The aggregate amount of power loads to be served at Tier 1 PF Rates has been estimated at 7,115 annual average megawatts for Fiscal Years 2014 and 2015. Actual Tier 1 Loads were 6,876 annual average megawatts in Fiscal Year 2013 (actual usage differed from forecast loads). Bonneville's obligation to sell power at Tier 1 PF Rates would be reduced if and to the extent that existing Federal System resources, including the Columbia Generating Station, were to decline in capability, although Tier 1 PF Rates would continue to recover the costs of the related resources. The aggregate amount of power available to be purchased at Tier 1 PF Rates may also be expanded in certain limited circumstances: (i) up to 70 annual average megawatts for a potential sale to DOE, and (ii) up to 250 annual average megawatts in aggregate, if necessary, for new Preference Customers and load growth of certain Indian tribe customers. Bonneville has had inquiries from some interested parties about becoming new Preference Customers; however, Bonneville cannot predict whether potential qualifying utilities will form, commence operation, or become Preference Customers, or the amount of power they will purchase from Bonneville at Tier 1 PF Rates.

Bonneville has adopted a "Tiered Rates Methodology" that defines the costs that are and will be allocated to Tier 1 PF Rates, including but not limited to: 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 Services rates), Federal System fish and wildlife costs, electric power conservation programs, power benefits (if any) to be provided to DSIs, and Residential Exchange Program benefits. Under the Tiered Rates Methodology, most of the benefits of seasonal surplus (secondary) energy from the Federal System are provided to Preference Customers in Tier 1 PF Rates. In the case of Slice, the related customers receive a proportionate share of Federal System seasonal surplus (secondary) to use for native loads (or to market in the case of a small portion of Slice which is a non-requirements product). The revenue benefits that Bonneville receives from its own marketing of seasonal surplus (secondary) are allocated to non-Slice Tier 1 PF Rates (primarily, to rates for Block and Load Following power products). See "BONNEVILLE LITIGATION—2010 and 2012 Power Rates Challenges."

Tier 2 PF Rates and Tier 2 Loads. In contrast to Tier 1, "Tier 2 Loads" are loads that a customer places on Bonneville that are incremental to the customer's right to purchase at Tier 1 PF Rates. Under the Tiered Rates Methodology, Tier 2 PF Rates recover only the cost to Bonneville of meeting Tier 2 Loads for Preference Customers that elect to purchase power from Bonneville to meet Tier 2 Loads, such purchases are 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 provides the customers the ability to rely entirely on Bonneville to meet all such loads throughout the entire 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.

Preference Customers have committed to the Tier 2 Load amounts they will place on Bonneville through Fiscal Year 2015. Bonneville is obligated to meet approximately 18 annual average megawatts in Fiscal Year 2014 and approximately 72 annual average megawatts in Fiscal Year 2015. In Fiscal Year 2013, Tier 2 Loads were 57 annual average megawatts. As required under the Long-Term Preference Contracts, those customers requesting that Bonneville meet their Tier 2 Loads through Fiscal Year 2019 have made their elections. However, the aggregate amount of Tier 2 Loads that Bonneville will be obligated to meet in Fiscal Years 2016 through 2019 will not be finally determined until just prior to the beginning of the particular power rate proceeding to establish the Tier 2 PF Rates in which the Tier 2 service will be provided. 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.

Comparison of Tier 1 PF Rates and Tier 2 PF Rates. Bonneville expects that Tier 1 PF Rates will be lower than Tier 2 PF Rates because the embedded cost structure for power from the existing Federal System (in general, as of the time of the commencement of power sales under the Long-Term Preference Contracts, which costs are and 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. In Fiscal Year 2013, average Tier 2 PF Rates were $46.63 per megawatt hour and average Tier 1 PF Rates were $29.48 per megawatt hour. Under the Final 2014-2015 Rate Proposal, average Tier 2 PF Rates are $39.86 per megawatt hour and average Tier 1 PF Rates are $31.50 per megawatt hour.

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 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 has led and is expected to lead Bonneville to acquire conservation resources and has led and may in the future lead Bonneville to acquire generation resources. The extent to which Bonneville does so will depend on the effects of electric power markets, power sales contract terms, 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 conservation 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. The Council also develops and periodically amends a fish and wildlife program for the Region.

In 2010, the Council released its Sixth Northwest Power Plan (the "Sixth Power Plan") according to which cost-effective energy efficiency could meet 85 percent of the new load from 2010 through 2030 (approximately 5,900 of 7,000 annual 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; (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.

The Council is currently preparing its Seventh Power Plan for actions over the five calendar years beginning with calendar year 2015, although the plan looks forward over a 20-year horizon. Bonneville expects that the Seventh Power Plan will carry forward many of the features of the Sixth Power Plan such as the reliance on energy efficiency and renewable energy to meet the Region's future power needs. Bonneville expects that the Council will issue the Seventh Power Plan near the end of calendar year 2015. Until the Seventh Power Plan is published, BPA continues to look to the Sixth Power Plan for guidance.

Bonneville continues to strongly support the Sixth Power Plan's reliance on energy efficiency and renewable energy (primarily wind power) to meet the Region's future load growth and expects that the 504 annual average megawatts share of the overall Regional target for public power loads (effectively, Preference Customer loads) will be achieved. Bonneville and its Preference Customers have already achieved much of the Council's public power target and is on pace to meet or exceed the target. Achieving the conservation targets helps Bonneville manage future load-growth and minimizes reliance on development of other resources in order to meet demand. See "—Bonneville's Resource Program and Bonneville's Resource Strategies."

Bonneville's Resource Program and Bonneville's Resource Strategies. Bonneville's long-range resource planning involves the evaluation of whether Bonneville may need to acquire resources to meet its power supply obligations and the best means by which to meet those needs. Bonneville periodically analyzes its needs for annual energy as well as monthly/seasonal heavy load hour energy, capacity in extreme weather events, and hourly balancing reserves. These analyses inform Bonneville's Resource Program, which evaluates the means to meeting power supply needs, and which Bonneville expects to update roughly every two years. Bonneville's most recently published Resource Program in Fiscal Year 2013 concluded that Bonneville can satisfy much of its expected supply obligation through Operating Year 2021 with electric power conservation and short-term power purchases from wholesale power markets.

Bonneville's evaluation of Federal System short-term peaking capacity needs indicates that Bonneville is minimally surplus to no longer surplus in peaking capacity under extreme conditions in winter and summer. The winter peaking capacity assessment in connection with the 2013 Resource Program changed significantly from the prior assessment, largely as a result of extreme-weather load differences, the expiration of certain winter purchases, and changes in Federal System generation forecasts.

Bonneville's 2013 Resource Program provides that Bonneville will take steps to address its peaking capacity needs by: (i) achieving the Sixth Power Plan conservation targets (which is expected to have the effect of reducing load thereby supplementing the existing capacity of the Federal System), and (ii) making market purchases of energy (market purchases during heavy load hours supplement Bonneville's ability to meet capacity needs). Bonneville will also explore, among other things, obtaining additional hydro-storage in Canada, the use of demand response, and the application of non-federal resource peaking capacity.

Short-Term Power Purchases. Under the Long-Term Preference Contracts, customers may meet their own incremental loads or turn to Bonneville to meet such loads. To meet potential new loads, and consistent the Resource Program, 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 coal- or 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 be able to meet more of its loads with seasonal surplus (secondary) hydroelectric power.

In contrast to a reliance on long-term generating 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 now treats some conservation costs as capital costs amortized over a period of 12 years, which reflects Bonneville's expectation of the period of benefit from conservation measures. Bonneville also issues bonds to the United States Treasury to finance conservation program investments. For several years prior to Fiscal Year 2012, Bonneville expensed the conservation measures in the period in which the expense was incurred.

To reduce the use of borrowing from the United States Treasury to finance electric power conservation measures, Bonneville is considering whether to seek to enter into resource acquisition agreements in which a third party would issue bonds, the proceeds of which would be used to fund such measures. The bonds would be secured by Bonneville's commitment to provide conservation acquisition payments in return for associated energy savings. Depending on a variety of factors, it is possible that this type of arrangement could fund $70 million or more per year of conservation investments, beginning in Fiscal Year 2016. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program."

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.

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.

Following years of negotiation and litigation with various parties over implementing the Residential Exchange Program, in July 2011, Bonneville, numerous Preference Customers and all six Regional IOUs entered into the "2012 Residential Exchange Program Settlement." The settlement reconfigures the Residential Exchange Program, fixing the amount of aggregate program benefits for the Regional IOUs from Fiscal Year 2012 through Fiscal Year 2028. As part of the settlement, the schedule of aggregate program benefits for the Regional IOUs begins at $259 million in each of Fiscal Years 2012 and 2013, and increases over time to $286 million in Fiscal Year 2028. The past erroneous overpayments of Residential Exchange benefits resulted in higher rate levels to Preference Customers than otherwise would have been the case. The settlement also assures that Preference Customers will receive remuneration for the past adverse rate effects caused by the overpayments to the Regional IOUs.

To recoup from Regional IOUs the past overpayments that they received, the actual Residential Exchange payments to the Regional IOUs are set to be approximately $77 million per year less than the nominal Residential Exchange benefits. These offsetting reductions (in effect since Fiscal Year 2012 and continuing through Fiscal Year 2019) are referred to by Bonneville as "Refund Amounts." Under the settlement, actual aggregate cash payments to the Regional IOUs are set at approximately $197.5 million per year during the 2014-2015 Rate Period. The value of such Refund Amounts is passed directly on to Preference Customers in the form of cash payments or credits on their power bills from Bonneville. As of the end of Fiscal Year 2013, the aggregate overpayment of Residential Exchange Program benefits that have not yet been recouped by Bonneville (and conveyed to Preference Customers) was approximately $432.8 million.

Certain parties filed litigation challenging the 2012 Residential Exchange Program Settlement. In October 2013, the Ninth Circuit Court issued an opinion dismissing the challenges and approving the settlement. No appeals were filed and the time in which to appeal has elapsed. While the litigation over the settlement has been resolved, the court has yet to issue dispositive orders dismissing all litigation related to the Residential Exchange Program. Bonneville and other settling parties have moved to dismiss the Residential Exchange Program litigation as all or partially moot due to the settlement. The court has not yet ruled on these motions. Notwithstanding the court's October 2013 decision, some litigants contend that certain issues in the Residential Exchange Program litigation have not been resolved by the settlement and intend to seek review by the court. Bonneville and other litigants will be filing papers with the court to determine whether any Residential Exchange Program issues remain following the court's settlement decision. 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's Program"). See "—Council's Fish and Wildlife Program." In addition, in the wake of certain listings of fish species under the Endangered Species Act (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's Program. The Council's Program calls for a variety of mitigation measures from habitat protection to main-stem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and require Bonneville to purchase power to fulfill contractual demands or to spill water and thereby forgo generation of electricity, for instance, those financial losses are counted as measures funded by Bonneville. While many of the measures in the Council's Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's Program measures, especially those designed to benefit species not listed under the ESA, are in addition to ESA-directed measures. See "—Council's Fish and Wildlife Program."

Bonneville's fish and wildlife costs fall into two main categories, "Direct Costs" and "Operational Impacts," both of which are driven primarily by ESA requirements. Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing projects in support of the Council's 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 (Columbia River Fish Mitigation), 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. Columbia River Fish Mitigation is described in "—The Endangered Species Act."

"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 operating constraints due to fish and wildlife protection. 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 measures. The following table shows Bonneville's Fish and Wildlife costs by category for Fiscal Years 2011 through 2013.

Fish and Wildlife Financial Impacts By Type
(Fiscal Years 2013-2011, dollars in millions)

	2013	2012	2011
Direct Costs	$ 461	$ 453	$ 422
Estimated Operational Impacts[1]:			
Replacement Power purchases	86	38	71
Foregone Power Revenues	135	152	157
Total Fish and Wildlife	**$ 682**	**$ 643**	**$ 650**

[1] **Non-GAAP financial information.**

The variations in Direct Costs from year to year are the result of changes in reimbursable/direct-funded projects and fixed expenses. The variations in Replacement Power and Foregone Power Revenues are the result of changes in prices due to energy market conditions and differences in monthly generation shape.

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 (also referred to as "Action Agencies"), can 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, over a dozen 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 the subject of litigation and judicial review and has resulted in court orders remanding prior biological opinions to the responsible federal agencies to correct deficiencies.

Operation of the Federal System hydroelectric dams consistent with the ESA 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 limitations, under certain water conditions, Bonneville has purchased and will 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 reduced the surplus energy Bonneville has available 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's Program, as in effect as of the beginning of Fiscal Year 2000, decreased Federal System generation capability by approximately 1,000 annual average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the NOAA Fisheries initial 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 approximately $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's Program, discussed below. Bonneville is also providing funding under the Columbia Basin Fish Accord funding agreements entered into with certain tribes and the states of Idaho, Montana, and Washington.

The Columbia Basin Fish Accords. Bonneville, the Corps, and Reclamation, and a number of Regional interests including tribes, an inter-tribal association, and the states of Washington, Montana and Idaho have signed a number of separate agreements to assure long-term fish and wildlife funding with respect to the Federal System. The foregoing agreements, collectively known as the Columbia Basin Fish Accords, are expected to improve habitat and strengthen fish stocks in the Columbia River Basin over the ten years beginning with Fiscal Year 2009.

Under the Columbia Basin Fish Accords, Bonneville committed to make available approximately $994 million over the ten-year funding period. Bonneville estimates that most of its funding commitments have been and will be for new work required to implement the applicable Columbia River System biological opinions and for work 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, which activities would otherwise face funding uncertainty.

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. Bonneville believes that the Columbia Basin Fish Accords also provide a high level of assured long-term ESA funding, which was a concern raised by the court in reviewing past biological opinions.

The 2014 Columbia River System Supplemental Biological Opinion. On January 17, 2014, NOAA Fisheries issued a Supplemental Columbia River System Biological Opinion for the calendar years 2014 through 2018 (the "2014 Columbia River System Supplemental Biological Opinion"), which addresses ESA-listed fish species affected by the operation of the hydroelectric dams on the Columbia and Snake Rivers. The 2014 Columbia River System Supplemental Biological Opinion supplements NOAA Fisheries' 2008 Columbia River System Biological Opinion as supplemented in 2010. The 2008 Columbia River System Biological Opinion was supplemented in 2010 and as so supplemented is referred to herein as the "2008/2010 Columbia River Biological Opinion."

The 2008/2010 Columbia River Biological Opinion and the records of decision adopted by each of Bonneville, the Corps, and Reclamation, to meet the implementation of the Reasonable and Prudent Alternative of the biological opinion, were challenged in litigation. In 2011, the United States District Court for the District of Oregon (the

“Oregon Federal District Court”) upheld the implementation of the biological opinion through calendar year 2013 as legally adequate under the ESA, and remanded the matter to NOAA Fisheries ordering it to issue a new or supplemental biological opinion by January 2014 and to identify specific mitigation measures and provide improved scientific support for the conclusion that those measures will avoid jeopardy to the listed species.

The 2014 Columbia River System Supplemental Biological Opinion responds to the court’s order. The 2014 Columbia River System Supplemental Biological Opinion continues many of the measures that were implemented, were being implemented, and were proposed to be implemented under the prior Columbia River System biological opinions. In producing the 2014 Columbia River System Supplemental Biological Opinion, NOAA reviewed the Action Agencies’ (Corps, Reclamation and Bonneville) implementation progress under the 2008/2010 Columbia River Biological Opinion to determine if it was proceeding as expected, reviewed the status of the species and new science on topics related to the biological opinion; scrutinized the detail provided by the Action Agencies on specific mitigation measures and analyzed the scientific support for those measures; and evaluated whether more aggressive action such as dam removal, additional flow or spill were necessary to meet the standards under the ESA. The 2014 Columbia River System Supplemental Biological Opinion documents NOAA Fisheries’ determination that the Action Agencies’ implementation of the Reasonable and Prudent Alternative of the 2008/2010 Columbia River Biological Opinion meets the legal standard under the ESA.

In addition, the 2014 Columbia River System Supplemental Biological Opinion continues certain elements of prior biological opinions relating to short-term and longer-term contingent actions that would be implemented, as appropriate, in the event of the occurrence of certain triggering events evidencing biological decline of the ESA-listed species. The potential short-term actions relate primarily to hydro-operations actions such as spill beyond that required to meet hydro-system dam fish passage survival performance standards, and fish transportation modifications, fish hatchery operations, fish predator management and fish harvest restrictions that can be implemented in less than a year. The potential longer-term actions include, among other items, alterations to fish predation management approaches, harvest practices, hatcheries, and hatchery practices, and study plans for hydro-system modifications, all of which would take more than one year to implement.

The 2014 Columbia River System Supplemental Biological Opinion also continues a plan for 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 a timetable for site-specific fish hatchery consultations and reforms, and proposed structural modifications to federally-owned hydroelectric dams of the Federal System.

The foregoing modifications were and are expected to be funded by specific federal appropriations, primarily to the Corps under the “Columbia River Fish Mitigation” program.” Bonneville expects that it will be responsible for including in its power rates as a repayment to the United States Treasury approximately 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. As of the end of Fiscal Year 2013, Bonneville was responsible for $1.32 billion of repayable appropriations for Columbia River Fish Mitigation, as allocated to the power purpose of the Corps’ Federal System hydroelectric projects. Bonneville expects the Columbia River Fish Mitigation program to receive appropriations ultimately totaling $2.1 billion. Currently, Bonneville forecasts that the portion of future Columbia River Fish Mitigation appropriations to be made and assumed by Bonneville as repayable appropriations obligations will be approximately $500 million over the next eight years, although the period could be longer depending upon timing of the receipt of appropriations from Congress and implementation by the Corps.

The 2014 Columbia River System Supplemental Biological Opinion also carries forward from prior biological opinions an approach to long-term contingency action in the event there is a significant decline in the status of a Snake River species. One contingency is a study of breaching one or more of the four lower Snake River dams of the Federal System, an action that would interfere substantially with hydro-electric generation of the Federal System. A feature of the 2014 Columbia River System Supplemental Biological Opinion carried forward from the 2008/2010 Columbia River System Biological Opinion (as included in the 2010 supplemental biological opinion) is that dam breaching 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.

Costs and Consequences of the 2014 Columbia River System Supplemental Biological Opinion. Many measures in the 2014 Columbia River System Supplemental Biological Opinion have been implemented, are currently being implemented, or would otherwise be implemented, including under the Columbia Basin Fish Accords and prior biological opinions relating to the Columbia River system. Certain measures involve long-term costs or expenses that are difficult to predict. Qualified by the foregoing and other uncertainties, Bonneville estimates that the 2014 Columbia River System Supplemental Biological Opinion, will not increase in aggregate the expense or capital portions of Bonneville's cost of service compared to the expenses and capital costs Bonneville forecast with regard to prior Columbia River System biological opinions dating back to 2008. In developing the Final 2014-2015 Rates, Bonneville made assumptions of the possible range of expected incremental costs that could arise under the 2014 Columbia River System Supplemental Biological Opinion. Bonneville believes that such assumptions remain reflective of the possible cost exposure to Bonneville of the biological opinion.

The 2014 Columbia River System Supplemental Biological Opinion has been challenged in litigation. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible future changes in Federal System dams or dam operations, under the ESA or other environmental laws, and whether the 2014 Columbia River System Supplemental Biological Opinion will, given the challenges in litigation, be upheld in court.

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 of the Federal System located on various tributary rivers within the Willamette River basin in western Oregon.

Bonneville and the State of Oregon have signed an agreement to permanently resolve longstanding wildlife mitigation issues associated with the Willamette River dams. Bonneville's total commitment under the agreement is $144.1 million (including inflation) through Fiscal Year 2025. In addition, Bonneville will continue funding the Oregon Department of Fish and Wildlife's operation and maintenance costs for Fiscal Year 2026 through Fiscal Year 2043 at levels to be negotiated based on historic funding levels and then-current needs and conditions.

While Bonneville has resolved many issues with the State of Oregon, it remains possible that NOAA Fisheries or others may seek more measures to benefit the listed species, which could result in further costs to Bonneville. 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.

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the Office of Management and Budget, DOE, and other agencies agreed to provide for certain federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision authorizes Bonneville to exercise its Northwest Power Act 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 approximately $85 million, $77 million, and $84 million in Fiscal Years 2011, 2012, and 2013 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.

Council's Fish and Wildlife Program. In 2000, the Council issued a Columbia River Basin Fish and Wildlife Program (the "Council's Program—2000") to mitigate the impacts of the operation of the hydroelectric dams of the Federal System on fish and wildlife in the Region, as provided under the Northwest Power Act. In general, Bonneville is charged with implementing the mitigation measures recommended by the Council. The Council's Northwest Power Act mitigation recommendations are in addition to actions to protect fish and wildlife under the ESA and other applicable laws. The Council's Program—2000, as thereafter amended by the Council, emphasizes an ecosystem approach to rebuilding fish and wildlife in the Columbia River basin.

In view of the increasing number of actions under the ESA in connection with listed fish populations affected by the Federal System, and in view of the potential for overlap or conflict of ESA-related actions with recommendations under the Council's Program—2000, the Council also sets forth an "Integrated Program" that integrates mitigation recommendations from both the Council's Program—2000 (as amended) and recovery actions under the ESA. The costs of the Integrated Program are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General." Integrated Program expense was $239 million, and Federal System capital investment was $52 million, in each case in Fiscal Year 2013. Bonneville forecasts that in Fiscal Year 2014, expenses and capital program investments will be $295 million and $50 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 2014-2015

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's Final 2014-2015 Rate Proposal for power and transmission rates of general applicability and FERC has granted final approval thereof. The Final 2014-2015 Rates for power for Preference Customers vary depending on the particular power product provided by Bonneville. Average PF Preference Rates (inclusive of the Slice, Block and Full Requirements products) increased by nine percent over the prior average rates, to $31.50 per megawatt hour. Under the Final 2014-2015 Rates, average Tier 2 PF Rates are 17.1 percent lower than in the prior rate period, declining to $39.86 per megawatt hour. Tier 2 PF Rates apply to incremental loads that Preference Customers require Bonneville to meet. Bonneville currently sells less than 100 annual average megawatts of power at Tier 2 PF Rates. For a discussion of Tier 1 PF Rates and Tier 2 PF Rates, see "—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Long-Term Preference Contracts and Power Products."

The Final 2014-2015 Rates continue the use of certain features (in some cases slightly modified) from prior final power rates. For instance, 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 revenue, and (ii) a CRAC that can increase certain power (and certain ancillary services) rate levels during the rate period.

The CRAC is designed to enable Bonneville to increase Power Revenues, primarily from the sale of Block and Load Following power products under the Long-Term Preference Contracts, by up to $300 million per fiscal year without a formal and time consuming rate proceeding. The CRAC is designed to trigger if certain financial performance measures reflective of Power Services' financial reserves decline to a threshold level ("CRAC Threshold"). The CRAC Threshold was not crossed to raise rate levels in Fiscal Year 2014. Bonneville believes that the CRAC Threshold will not be crossed to raise rate levels in Fiscal Year 2015. While the amount of additional recoveries under the CRAC is capped at $300 million in a fiscal year, Bonneville nonetheless reserves the ability to institute another full rate proceeding and increase rates or rate levels in the rate period.

Under the power rates portion of the Final 2014-2015 Rates, Bonneville utilizes updated versions of the National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment ("NFB Adjustment") and Emergency National Marine Fisheries Service Federal Columbia River Power System Biological

Opinion Surcharge ("Emergency NFB Surcharge"). These features enable Bonneville to recover additional amounts or in accelerated time frames during the 2014-2015 Rate Period to address unexpected costs or decreases in revenue that could arise from ESA litigation relating to the Federal System. See "—Fish and Wildlife—The Endangered Species Act."

The risk mitigation tools underlying the power rates also include relying on certain RAR derived from Power Services operations and relying on the availability of funds, if needed during the rate period, under Bonneville's $750 million short-term credit facility with the United States Treasury to cover certain operating expenses. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Reserves" and "—Banking Relationship between the United States Treasury and Bonneville."

The Final 2014-2015 Rates for power continue the availability of a feature parallel to, but the reverse of, the CRAC, referred to as the Dividend Distribution Clause ("DDC"). The DDC could decrease certain power and ancillary services rate levels in either year of the rate period, also based on financial results. The DDC did not trigger for Fiscal Year 2014 and Bonneville believes that the DDC will not trigger for Fiscal Year 2015.

Historical PF Preference Rate Levels

As shown in the following table, Bonneville's average PF Preference Rates have remained between $20 per megawatt hour and $35 per megawatt hour in nominal (actual) dollars, and between $20 per megawatt hour and $30 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2014. These estimates include average PF Preference Rates expressed on a dollar-per-megawatt-hour basis, exclusive of Slice rates. While most PF Preference Rates are established on a dollar-per-megawatt hour basis, Slice rates are set on the basis of dollars-per-percentage-point of Slice. The data also exclude PF Exchange Rates which are used in determining Residential Exchange benefits, and Tier 2 PF Rates, which Bonneville instituted in Fiscal Year 2012 to recover the cost of meeting certain incremental loads.

Bonneville's average PF Preference Rates increased substantially in Fiscal Year 2002 to recover from the effects of the West Coast Power Crisis in 1999-2001. See "BONNEVILLE LITIGATION—Litigation and Related Administrative Disputes in Connection with the West Coast Power Crisis in 1999-2001." Since then, such rates have been stable, especially when viewed from an inflation-adjusted perspective, as shown in the following chart.

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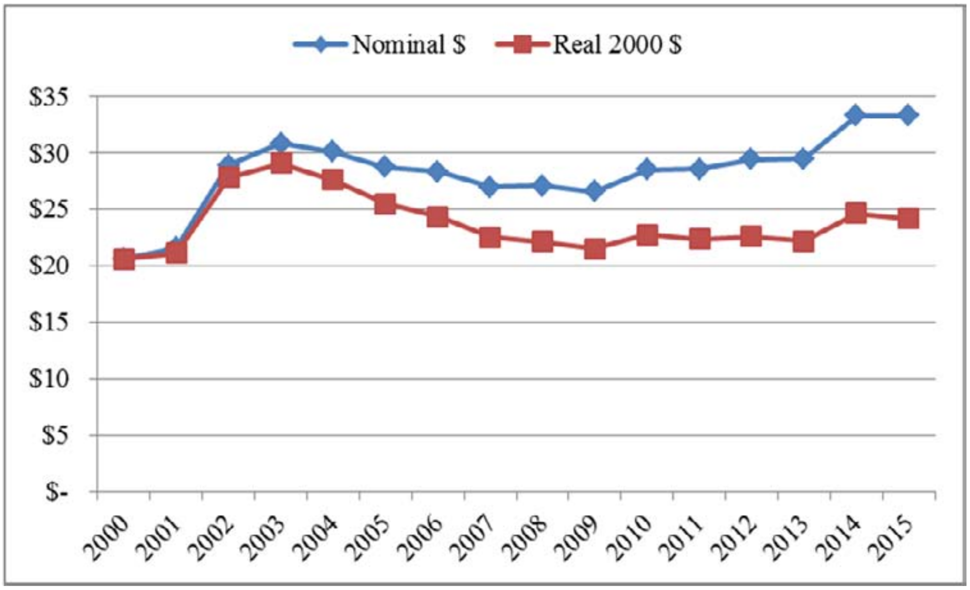
Historical Average PF Preference Rates
Nominal (Actual) and Real (Inflation-Adjusted) Average PF Preference Rate Levels, Per Megawatt Hour, Fiscal Years 2000—2015



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 Federal Power Act ("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 Energy Policy Act of 1992 ("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 FPA sections 211 and 212.

Shortly after the issuance of Order 888-A, 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 the Energy Policy Act of 2005 ("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 approximately $804 million in revenues from the sale of transmission and related services, or approximately 25 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 2013.

Bonneville's Transmission Services provides transmission service under its Open Access Transmission Tariff ("Tariff"). Two transmission services are offered under the Tariff: Point-to-Point and Network Integration. These services are available to all customers regardless of whether they are transmitting Federal or non-federal power. Network Integration service is used by many Bonneville Preference Customers, (as well as others), 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 portion 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 affect 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 charge is based on actual usage and thus can vary from month to month 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 the current rate period (Fiscal Years 2014-2015), a large Preference Customer that purchases very little transmission for its own resources pays Bonneville approximately $4.26 per megawatt hour for transmission service and approximately $31.50 per megawatt hour for electric power.

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System which is operated and maintained by Bonneville and owned or leased 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), 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; 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. 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. In recent years, many of the requests for new transmission service have been submitted by customers 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 2014 through 2023 averaging approximately $417 million annually. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program" and "—Bonneville's Non-Federal Debt."

If a customer requests to interconnect a new power generation project to the Federal Transmission System and Bonneville determines that additional facilities need to be constructed to accommodate the request, Bonneville may seek advance funding of its transmission costs for the necessary investments from the customer seeking the interconnection. If the necessary facilities are integrated into Bonneville's network, Bonneville returns to the customer the amounts it advanced for construction of the new facilities in the form of (i) credits against the customer's monthly bills for firm transmission service, or (ii) in some cases, cash payments to the generator or its assigns. Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were $41 million in Fiscal Year 2013 and will be $40 million in Fiscal Year 2014. 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 interconnect to 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 all other customers from costs they would otherwise bear due to the integration costs of the new facilities.

FERC has approved Bonneville's "Network Open Season" process, in which Bonneville aggregates pending requests for transmission service in order to study and otherwise evaluate the new transmission facilities that it would have to construct to provide that service. Bonneville developed this process to help ensure that it would accurately identify plans of service for serving new requests, recover the costs of any new transmission facilities that are constructed, and avoid stranded transmission investments. Bonneville has implemented several new aspects to the Network Open Season process since its inception, and has also discussed further modification to the Network Open Season process in recent years. Thus, Bonneville may implement still more changes to the Network Open Season process in the future.

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 of transmission that customers will actually commit to, 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 a discussion of the applicability of FERC's cost allocation methodology under Order 1000 (as hereinafter defined), see "—Bonneville's Participation in Regional Transmission Planning."

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 of 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 public utilities (the utilities subject to FERC regulation, which does not include government entities such as Bonneville) 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 authorizes FERC to require an "unregulated transmitting utility" (a term that includes Bonneville), to provide transmission services to others (1) at rates that are comparable to those that the utility charges itself, and (2) 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 to it. However, 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 in 2012 seeking reciprocity approval. Several parties filed protests to certain aspects of Bonneville's new Order 890 tariff and FERC issued an order denying Bonneville reciprocity. Bonneville did not file for rehearing. Bonneville's Order 890 Tariff includes certain features that seek to address Oversupply Management in times of high renewable energy generation and low energy loads. 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 transmission providers that 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 them 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.

General - Bonneville's Transmission and Ancillary and Control Area 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, and, as to transmission rates, equitably allocate the costs of the federal transmission system between federal and non-federal power.

Fiscal Years 2014-2015 Rates for Transmission and Ancillary and Control Area Services

Bonneville's Fiscal Years 2014-2015 transmission rates, which FERC approved in April 2014, reflect an average increase of approximately 11 percent over Fiscal Years 2012-2013 rate levels. This is the first increase to Bonneville's general transmission rates in eight years.

Bonneville's Fiscal Years 2014-2015 transmission rate schedules also include rates for a number of ancillary and control area services. Power Services provides generation inputs, a portion of the available capacity and energy from the Federal Columbia River Power System to enable Transmission Services to provide ancillary and control area services. Transmission Services, which purchases generation inputs from Power Services, sets ancillary and control area service rates that recover the generation inputs costs.

Transmission Services' Largest Customers

The following table lists Transmission Services' ten largest customers in terms of their percentage contribution to Transmission Services' overall sales revenue in Fiscal Year 2013. The table also notes the type of entity for each customer.

Transmission Services' Ten Largest Customers By Sales[(1)]
(Percentage of Transmission Services' Sales Revenue in Fiscal Year 2013)

Customer Name (Class)	Approximate % of Sales
Puget Sound Energy Inc. (IOU)	11%
PacifiCorp (IOU)	11%
Portland General Electric Company (IOU)	8%
Powerex Corp. (Power Marketer)	7%
Snohomish County PUD No. 1 (Preference)	5%
Iberdrola Renewables Inc. (Wind Developer)	5%
City of Seattle, City Light Dep't (Preference)	4%
Hermiston Power LLC (Power Marketer)	3%
Clark Public Utilities (Preference	2%
Cowlitz County PUD No. 1 (Preference)	2%

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(1) Excludes inter-business line transactions between Power Services and Transmission Services. Transmission Services obtains electric power from Power Services to enable Transmission Services to provide transmission related products, particularly ancillary services.

Bonneville's Participation in Regional Transmission Planning

Bonneville is currently a member of "ColumbiaGrid," a regional transmission planning organization of eight Pacific Northwest utilities. ColumbiaGrid is not a Regional Transmission Organization ("RTO") under FERC policies.

FERC has provided transmission planning direction in its "Order 1000," dated July 21, 2011 and prior orders. Order 1000 requires jurisdictional utilities to participate in certain regional transmission planning processes and in regional and interregional cost allocation methodologies for transmission projects. Although Order 1000 does not apply to non-jurisdictional utilities such as Bonneville, FERC encourages non-jurisdictional utilities to comply by requiring compliance in order to obtain reciprocity and by indicating that it might exercise its authority to require such utilities to comply if they do not do so voluntarily. Although as yet untested in court, 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.

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 mandatory cost allocation provisions, may conflict with Bonneville's statutory obligations and authority with respect to the Federal Transmission System. 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's Order on Rehearing dated May 17, 2012, made no substantive changes nor did it specifically address Bonneville's issues regarding mandatory cost allocation. Certain other parties have filed petitions for judicial review of Orders 1000 and 1000-A. Oral argument was held March 20, 2014, before the United States Court of Appeals for the District of Columbia Circuit.

Bonneville submitted Order 1000 revisions to the transmission planning provisions of Bonneville's tariff for approval pursuant to FERC's reciprocity policy on October 11, 2012. All of the revisions were consistent with Bonneville's statutory obligations regarding cost allocation. FERC rejected the parts of the filings that would have allowed Bonneville to deviate from the Order 1000 cost allocation provisions based on Bonneville's studies. Bonneville sought clarification, or in the alternative rehearing, of FERC's June 20, 2013 order via a filing made on July 22, 2013. Other non-jurisdictional planning participants concurrently filed a request for rehearing. FERC has not acted on the requests.

On December 17, 2013, other Northwest utilities made further compliance filings in accordance with FERC's June 20, 2013 order; however, Bonneville did not make further compliance filings. Bonneville intends to await FERC's order on Bonneville's request for clarification or rehearing before deciding whether to make a further reciprocity filing. Bonneville and all the other non-jurisdictional and jurisdictional planning parties continue to participate in the ColumbiaGrid regional planning process.

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 of 1944. 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 justification 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.

Under the Northwest Power Act, FERC's review of Bonneville's power and transmission rates involves three standards. 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 cost allocation for purposes other than equitable allocation of transmission costs.

FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a rate in lieu of a proposed rate that FERC finds does not meet the applicable standards. In the opinion of Bonneville's General Counsel, if FERC were to reject a proposed Bonneville rate, FERC would be limited to remanding the proposed rate to Bonneville for further proceedings as Bonneville deems appropriate. On remand, Bonneville would reformulate the proposed rate to comply with the statutory ratemaking standards. If FERC has previously given the rate 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 see "—Energy Policy Act of 2005."

Judicial Review of Federal Energy Regulatory Commission Final Decisions

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 Pacific 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 has incurred approximately $400,000 of environmental protection costs at one site but due to a "no further action" determination by the United States Environmental Protection Agency during the summer of 2013, Bonneville does not expect to incur any additional liability for the site. 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 unregulated utilities' 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. See "—Wind Generation Development and Integration into the Federal Transmission System." for discussion of FERC exercising its authority under this provision in response to a complaint filed by certain customers against Bonneville.

(ii) 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 Regional Transmission Planning.

(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.

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue 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 is 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, or assessed by FERC itself. DOE has asserted in litigation in the United States Circuit Court for the District of Columbia that Congress has not authorized monetary penalties to be imposed on federal agencies, such as Bonneville. Bonneville has received notices of alleged violations of certain mandatory reliability standards from the Western Electricity Coordinating Council (WECC). WECC acts for the North American Electric Reliability Corporation (NERC) which is the ERO established by FERC. Processing of these alleged violations is stayed pending a decision in the litigation brought by DOE. Even assuming that DOE were not to prevail in the litigation, it is not certain that all potential monetary penalties for alleged violations of the reliability standards would be fully assessed. To date, Bonneville estimates that maximum potential asserted penalties would not exceed $5 million for alleged violations of the standards, assuming that the full penalty were to be ultimately assessed for all alleged violations.

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 forward physical electric power transactions, which call for physical delivery of electric power, and occasionally in commodity option transactions, to market energy and to purchase energy to meet needs and to hedge sales and purchases. Bonneville also engages from time to time in exchange-traded, power-related futures to manage risk in its market purchases and sales of electricity. Such transactions are governed by Bonneville's transaction risk management policies that establish limits around open positions and posted margins. Bonneville does not currently hold any other types of financial swaps or future contracts such as interest rate swaps. 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 September 2024. On December 13, 2013, the United States Entity sent a final regional recommendation concerning the future of the Columbia River Treaty to the United States Department of State. In general, the regional recommendation is to modernize the Treaty to more fairly reflect the distribution of operational benefits between the United States and Canada, to ensure that flood risk management and other key river uses are preserved, and to address key ecosystem functions in a way that complements the significant investments made to protect fish and wildlife over the past three decades. The Department of State will use the final recommendation to begin a federal policy review process to determine whether to proceed with a Treaty modernization effort with Canada. The final recommendation submits that the Pacific Northwest and the nation would benefit from modernization of the Treaty post-2024. Now that the final recommendation has been delivered to the United States Department of State, the United States government will formally take up the question of the Columbia River Treaty. That process will be a federal interagency review under the general direction of the National Security Council on behalf of the President of the United States.

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of 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.

Federal Debt Ceiling

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. 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 condition, including, among other things, restricting Bonneville's ability to borrow either short- or long-term from the United States Treasury and Bonneville's access to the Bonneville Fund to meet its payment obligations, including payments under the Net Billing Agreements, the 1989 Agreement, or the Direct Pay Agreements. In Fiscal Year 2014, Congress enacted legislation assuring that the debt ceiling would not be reached until at least March 15, 2015. Bonneville is unable to predict whether the United States will reach the United States' debt ceiling in the future.

Federal Sequestration for Fiscal Year 2013 and 2014

Bonneville is a federal agency and is subject to applicable federal budget laws. In Fiscal Year 2012, and again in Fiscal Year 2013, Congress enacted certain laws, which, when applied together with provisions of pre-existing federal budget law, resulted in or will result in across-the-board reductions in budgetary resources in the affected budget years for many federal programs, projects, and activities, with the consequence that the authority to incur obligations and make expenditures with respect to the affected federal programs, projects and activities has been similarly reduced. This reduction of authority to incur obligations and make expenditures is referred to as sequestration.

Under longstanding federal budget law and federal budget law practice, Bonneville's operations have been exempt from sequestration; however, one effect of the United States Office of Management and Budget's application of the foregoing Congressional enactments has been to subject certain of Bonneville's administrative costs to sequestration in Fiscal Years 2013 and 2014. The sequestration has not and will not adversely affect the operation of the Federal

System or Bonneville's authority or ability to meet its existing contractual obligations, including payments with respect to debt service on the 2014-C Bonds under the Net Billing Agreements, the 1989 Agreement, or Direct Pay Agreements. Bonneville estimates that the foregoing sequestrations will ultimately result in a reduction in expenditures for Bonneville's administrative activities in the amount of approximately $15 million in Fiscal Years 2013 and 2014 combined.

Direction or Guidance from other Federal Agencies

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 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 has initiated a cap and trade platform that became active 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. Climate change may also affect the timing and type of seasonal precipitation, which may affect how the Federal System is operated.

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."

Preparedness and Cyber Security

In addition to normal storm and wildfire response procedures to maintain the integrity of the Federal Transmission System, Bonneville has a Continuity of Operations program that has coordinated the development of plans, systems and facilities to continue to operate through, or quickly recover from, a major disruption such as a Regional earthquake. Bonneville is completing a redundant system control center that will be geographically separated from the existing control center, one east and one west of the Cascade Mountains, in areas not subject to the same vulnerabilities. The eastern control center is expected to be functioning by the fall of 2014. In a major disruptive event, either control center will be capable of managing transmission capacity and power sales as well as coordinating power generation operations.

New technical cyber vulnerabilities are discovered in the United States daily. In addition, cyber attacks have become more sophisticated and increasingly are capable of impacting industrial control systems and components. To face these and other challenges of cyber security Bonneville has taken several key steps and has plans for expanding its cyber security capabilities. Bonneville has staffed an Office of Cyber Security with certified and trained professionals and has organized its cyber security teams into several groups, including qualified internal attackers and assessors to test systems and intelligence and threat analysts to stay abreast of new vulnerabilities, assess exposure and respond accordingly to mitigate threats and share information. Bonneville has also developed alliances within the federal government and the Electric Sector Information Sharing and Analysis Center, to deploy intelligent devices to monitor external threats from the Internet, and begun planning a Cyber Security Operations and Analysis Center to improve Bonneville's capability and situational awareness.

Bonneville has enhanced its operational security through the implementation of a prioritization of real time cyber security controls called the SANS Top 20 and the measurement of Bonneville's capability using the electric power sector's capability model for cyber security (the Electricity Sector Cybersecurity Capability Maturity Model). Bonneville believes that these changes will help it face the challenge of increasing use of digital devices and increasing threats.

Wind Generation Development and Integration into the Federal Transmission System

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 4,847 megawatts of wind generation facilities are now interconnected to the Federal Transmission System. Bonneville expects that an additional 60 megawatts of wind power will be integrated by the end of September 2014. The rate of growth of wind energy development in the Region has slowed. Nonetheless, Bonneville expects that additional wind generation investments will continue to be made in the Region for the foreseeable future, in part because of state laws in the western United States which now set forth renewable energy portfolio requirements applicable to electric power utilities.

From a power marketing perspective, the development of large amounts of wind generation in the Pacific Northwest has also affected power market prices and the revenue Bonneville obtains for its surplus power sales, in particular sale of seasonal surplus (secondary energy). It has also resulted in the provision by Power Services of generation and supporting power services to support ancillary services needed for wind energy integration.

Integrating new resources (wind or otherwise) has required and may continue to require additional transmission facility investments, such as new transmission lines and substations or improvements to existing facilities, in order to transmit the additional electric power. In addition, integration of wind energy poses operational challenges to assure system-wide reliability and the efficient and effective transmission of wind generation to loads. From an electric power system perspective, wind energy is intermittent and may not be available to be called on when needed. Average generation over a year for all wind generation in the Region is approximately 30 percent of the installed capacity of the wind generation facilities. Furthermore actual output can vary substantially in relatively short time frames. This means that other generating resources must be available to increase generation to meet sudden declines in wind generation and to be scaled back to accommodate upsurges in wind generation.

Finally, in spring and summer months, in certain circumstances of high stream flows and high turbulence, water must run through hydroelectric turbines (this unavoidably creates electric power that must be consumed) to suppress the amount of dissolved gases in the river system to be within limits established under the ESA and the Clean Water Act (the "CWA"). The gases can be harmful to fish, including fish species listed under the ESA. The resulting hydroelectric energy has to be used (taken to load). Bonneville refers to this as "oversupply" or "over-generation." Oversupply can be resolved operationally by the substitution ("displacement") of non-federal generation with Federal System hydropower. Historically, Bonneville has resolved oversupply problems by offering to displace non-federal generation with low-cost or free Federal System hydropower. Wind generators, however, receive financial incentives, such as federal and state tax credits based on actual electric power generation. Thus, renewable generators do not have any incentive to accept displacement with low-cost or free Federal System hydropower.

With the increasing amounts of wind energy in Bonneville's balancing authority area, the potential for oversupply has increased. Large amounts of wind generation and hydroelectric generation (usually in the spring and summer) at times of low demand (usually at nighttime) can lead to situations in which - Bonneville must displace wind generators in order to mitigate excess gas levels for purposes of fish survival.

Bonneville's Oversupply Management

Bonneville's approach to managing oversupply to assure that wind generation integration does not adversely affect compliance with CWA and ESA fish requirements has evolved. A central feature of Bonneville's oversupply management is to displace wind generation at times when (i) aggregate electric generation exceeds electric system demand, (ii) increased hydroelectric generation is necessary to keep dissolved gas concentrations within acceptable limits, and (iii) displacement of non-federal generation with low-cost or free Federal System hydroelectric power is inadequate to mitigate excess gas levels.

Environmental Redispatch Policy

In May 2011, Bonneville issued an Environmental Redispatch Policy under which Bonneville displaced wind generators without compensation during oversupply events. In Fiscal Year 2011, acting under this policy, Bonneville displaced approximately 97,500 megawatt-hours of generation with free Federal System hydroelectric power. Several parties filed petitions with the Ninth Circuit Court in July 2011, seeking direct court review of Bonneville's policy. These cases are currently being briefed. In addition, several wind generators and other transmission customers filed complaints with FERC. In December 2012, FERC held that Bonneville's policy did not provide transmission service on terms and conditions that were comparable to those under which Bonneville provides transmission service to itself, as required under Section 211A of the FPA. FERC also ordered Bonneville to file tariff revisions that ensured comparable transmission service. Certain Preference Customers and others have filed challenges in the Ninth Circuit Court seeking to set aside the FERC order. These cases are currently being briefed.

Oversupply Management Protocol

In March 2012, in response to FERC's order on the Environmental Redispatch Policy, Bonneville filed with FERC a proposed Open Access Transmission Tariff revision, referred to herein as the Oversupply Management Protocol or OMP to manage over-generation events. The OMP provided that, if other actions were insufficient to manage oversupply, Bonneville would displace wind generators and compensate them for the displacement. The OMP set specific costs for which wind generators could be compensated, including the value of lost production tax credits and renewable energy credits, and with respect to power sales agreements executed on or before March 6, 2012, lost revenues and penalties for the failure to deliver wind energy. Bonneville requested FERC approval of the OMP through March 2013. Shortly thereafter, several parties filed petitions with the Ninth Circuit Court seeking review of the OMP. These cases are currently stayed.

Along with its OMP filing, Bonneville also informed FERC that it planned to conduct a rate proceeding and make an initial rate proposal to allocate 50 percent of OMP costs to Power Services' rates (borne primarily by Preference

Customers), and 50 percent of OMP costs to wind generators receiving compensation under the OMP. Bonneville initiated a formal rate case in November 2012.

In December 2012, FERC disapproved the proposed cost allocation but conditionally approved the terms and conditions of the OMP, provided that Bonneville files an acceptable cost allocation proposal. In March 2013, Bonneville re-filed the OMP with FERC, addressing the changes FERC ordered to the terms and conditions, and asked FERC to approve the OMP through September 30, 2015. FERC has not yet ruled on Bonneville's filing. In May 2013, various customers again petitioned the Ninth Circuit Court for review of Bonneville's decision to renew the OMP. These cases are currently stayed.

In April 2013, in response to FERC's rejection of Bonneville's initial rate proposal, Bonneville issued a supplemental proposal proposing to allocate OMP costs to all transmission customers using the Federal Transmission System at the time of the over-generation event. In March 2014, Bonneville issued the final record of decision and filed the final rate proposal with FERC. The rate proposal proposes to allocate costs only to generators that are located within Bonneville's balancing authority area based on transmission use.

From March 2012 to August 15, 2012, Bonneville displaced 49,654 megawatt hours of Fiscal Year generation resulting in eligible displacement costs of approximately $2.7 million. Bonneville will recover these costs in accordance with the final rate approved by FERC. Bonneville did not use OMP in Fiscal Year 2013 and has not used OMP to date in Fiscal Year 2014. Bonneville estimates that, on an expected value basis under the OMP, it will compensate wind generators an average of approximately $10 million per fiscal year. Under extreme conditions of very high streamflows, high wind generation and low power loads, compensation could exceed $50 million in a given fiscal year.

The OMP does not address any claims for damages associated with Bonneville's implementation of its Environmental Redispatch Policy.

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 appropriated 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, 2013, Bonneville had repaid $11 billion of principal of the Federal System investment and had approximately $4.3 billion principal amount outstanding with regard to such appropriated investments and $3.9 billion principal amount outstanding in bonds issued by Bonneville to the United States Treasury. Congress has continued to, and is expected to continue to, appropriate amounts for certain fish and wildlife investments in the Federal System. See the discussion of the Columbia River Fish Mitigation in "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

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 $13 million and $61 million per year over the next ten years.

Bonneville's Treasury 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, bonds in the principal amount of $3.9 billion were outstanding as of the end of Fiscal Year 2013. 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 the end of Fiscal Year 2013, the interest rates on the outstanding bonds ranged from 0.2 percent to 7.4 percent with a weighted average interest rate of approximately 3.8 percent. The original terms of the outstanding bonds vary from four to 30 years. As of the end of Fiscal Year 2013, Bonneville's outstanding bonds issued to the United States Treasury included $300 million in variable rate bonds at an average interest rate of 0.1 percent at such time. The term of the bonds is limited by the average expected service life or the maximum repayment period, which ever is shorter, of the associated investment: 35 years for transmission facilities, 50 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") governing the terms by which Bonneville borrows from the United States Treasury. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $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 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 interest credits 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 credits were earned, and will continue to be earned to the extent applicable, 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 invests the applicable cash reserves in the Bonneville Fund in certain interest bearing securities issued by the United States Treasury. The fund balance interest earnings under the Investment MOU have been and are expected by Bonneville to be lower than the prior interest credit practice would have provided.

Bonneville's Non-Federal Debt

To meet its capital program, Bonneville has relied on the Congressionally-enacted authority to borrow from the United States Treasury; however, Bonneville has also entered into various arrangements to meet its capital program which involve debt issued by third parties, the repayment of which is secured by Bonneville financial commitments. Bonneville has also employed electric power prepayments as a funding source. Bonneville refers to these commitments as Non-Federal Debt. As of September 30, 2013, aggregate Non-Federal Debt outstanding was approximately $6.8 billion. By way of comparison, as of September 30, 2013, the principal amount of unrepaid appropriations for Federal System investments was approximately $4.3 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was $3.9 billion. Described below are the currently outstanding forms of Non-Federal Debt. For a description of possible Non-Federal Debt transactions in the near future, see "—Bonneville's Capital Program—Possible Non-Federal Debt Activities in the Near Future."

Energy Northwest Net Billed Projects Bonds

Energy Northwest bonds issued for the Net Billed Projects ("Net Billed Bonds") represent the largest single component of Non-Federal Debt: $5.45 billion out of a total of $6.8 billion aggregate Non-Federal Debt, as of the end of Fiscal Year 2013. Bonneville's obligations with respect to the costs of the Net Billed Projects are described in the Official Statement under "SECURITY FOR THE NET BILLED BONDS."

Bonneville's Transmission Facility Lease-Purchase Program

One type of Non-Federal Debt involves the entry by Bonneville into lease-purchase commitments to acquire the use of transmission assets owned by a third party. Bonneville's lease-purchase payments are pledged by the related project owner to the payment of certain short-term bank loans the owner incurs or long-term bonds the owner issues to the public. The proceeds of the bank loans or bonds are used to fund the acquisition of and or construction, installation, and equipping of, the related facilities. Under these transactions, the related bonds and bank loans are secured solely by Bonneville's payments under the related lease-purchase agreement; furthermore, Bonneville's related lease rental payments are not conditioned on the completion, suspension, or termination of the related facilities.

The aggregate principal amount of outstanding bank loans and publicly-issued bonds associated with Bonneville's lease-purchase agreements, together with the principal amount associated with certain pre-existing capital leases, was $936 million as of September 30, 2013. Of the foregoing aggregate amount, the aggregate outstanding principal amount of publicly-issued lease-purchase bonds was approximately $205 million.

Bonneville has entered into short-term and long-term lease-purchase arrangements with Northwest Infrastructure Financing Corporation and five affiliate corporations (collectively, the NIFCs) and with the Port of Morrow, Oregon (the "Port").

In Fiscal Year 2013, the Port issued approximately $85 million in long-term, lease-purchase bonds having a final maturity of September 1, 2042. The Port used the bond proceeds to acquire the related facilities from the prior owner of the facilities (one of the NIFCs), which then repaid in full short-term bank loans that it (the prior owner) had incurred to finance construction of the facilities. Bonneville expects to continue to participate in similar financings where short-term lease-purchases secure construction loans that are repaid with the proceeds of long-term bonds secured by subsequent long-term lease-purchases.

Electric Power Prepayments

In Fiscal Year 2013, Bonneville and four Preference Customers agreed to separate electricity prepayment arrangements in which the Preference Customers provided 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. The participating customers are entitled to future deliveries of a portion of the electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments is and will be reflected as fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville received $340 million in aggregate of prepayments from the participating customers. The offsetting prepayment credits are set at $2.55 million per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028.

Bonneville expects to complete expending the prepayments on Federal System hydroelectric facility investments by the end of Fiscal Year 2015. As of September 30, 2013, outstanding Non-Federal Debt associated with electric power prepayments was $335 million.

Resource Acquisitions

In this form of Non-Federal Debt, Bonneville enters into resource acquisition agreements in which a third party issues bonds, the proceeds of which are used to construct or acquire generating facilities or to fund energy conservation measures, the project capability or conservation savings of which are provided to Bonneville. As of September 30, 2013, outstanding Non-Federal Debt for generating resource acquisitions was $106 million, and outstanding Non-Federal Debt for electric power conservation resource acquisitions was $6 million.

The following table depicts the types and amounts of Non-Federal Debt outstanding as of the end of each of Fiscal Years 2011 through 2013.

Non-Federal Debt, Fiscal Years 2011-2013

Non-Federal Debt Outstanding
(Dollars in thousands)

Projects Financed with Non Federal Debt	**2013**	**2012**	**2011**
Non-Federal Generation			
Columbia Generating Station	$3,175,659	$3,224,040	$2,487,355
Cowlitz Falls	87,995	104,650	116,780
Non Federal Generation	3,263,654	3,328,690	2,604,135
Terminated Generation			
Nuclear Project No. 1	1,048,005	1,321,060	1,573,805
Nuclear Project No. 3	1,229,245	1,395,405	1,495,480
Terminated nuclear facilities	2,277,250	2,716,465	3,069,285
Terminated Northern Wasco Hydro Project	18,375	19,735	21,740
Sponsored Conservation			
Tacoma	3,495	5,120	6,675
Conservation and Renewable Energy	3,004	5,870	11,200
Sponsored conservation	6,499	10,990	17,875
Lease-Purchase Program/Capital Leases	936,182	788,503	559,556
Customer prepaid power purchases	334,909		
Total Non-Federal Debt	$6,836,869	$6,864,383	$6,272,591
Projects Financed with Federal Debt			
Federal Appropriations	4,291,457	4,246,022	4,349,503
Borrowings from U.S. Treasury	3,885,040	3,420,040	2,943,440
Total Federal Debt	$8,176,497	$8,131,062	$7,292,943
Total Debt	**$15,013,366**	**$14,995,445**	**$13,565,534**

To the extent that Bonneville has entered into (or will enter into) arrangements involving Non-Federal Debt secured by cash payments by Bonneville, such as transmission facility lease-purchase arrangements and electric power conservation or generating resource acquisitions, the related debt service costs are and will be payable on the same parity as Net Billed Project costs (including debt service on the 2014-C Bonds and other Net Billed Bonds) in the order in which Bonneville's costs are met. See "—Order in Which Bonneville's Costs Are Met." To the extent that Bonneville uses non-United States Treasury sources that involve the provision by Bonneville of financial credits or offsets, as in the case of electric power prepayments, such obligations may reduce the amount of cash available in the Bonneville Fund to meet Bonneville's cash payment obligations, including to meet debt service on the 2014-C Bonds and other Net Billed Bonds.

Bonneville's Capital Program

Bonneville operates in a capital intensive industry and expenditure levels for its capital program have been substantial. The following table depicts Bonneville's capital investment levels by asset category for Fiscal Years 2009-2013. The following table reflects Bonneville's direct capital program only and excludes appropriated capital funding received by the Corps for the Columbia River Fish Mitigation program and capital investments associated with the Columbia Generating Station.

Historical Capital Spending by Program by Fiscal Year[1]
(Dollars in millions)

	2009	2010	2011	2012	2013	Total
Transmission	$377	$470	$522	$557	$506	**$2,431**
Federal System Hydro	140	148	200	214	206	**909**
Energy Efficiency	17	58	162	80	78	**394**
Fish and Wildlife	29	41	91	58	52	**271**
Facilities, Information Technology, Security	31	45	36	45	40	**198**
Total	**$593**	**$762**	**$1,012**	**$953**	**$883**	**$4,203**

(1) Totals may not add due to rounding.

To date Bonneville has met its capital program needs through various sources that include borrowing from the United States Treasury, and transactions involving Non-Federal Debt, as described above. Bonneville also uses funds from reserves and funds from customers in connection with "Projects Funded in Advance." Projects Funded in Advance are specific transmission capital investments that are made by Bonneville in the Federal Transmission System at the request of a customer or to meet a customer's transmission needs. The customer provides funds to Bonneville to construct all or a portion of the related facilities and receives offsetting payment credits in future transmission bills from Bonneville. Bonneville owns the facilities in its own name. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System." The following table presents Bonneville's capital funding sources for Fiscal Year 2009 through Fiscal Year 2013. It excludes capital investments for the Columbia Generating Station and for the Columbia River Fish Mitigation as appropriated by Congress to the Corps.

Historical Capital Funding by Source and Fiscal Year[1]
(Dollars in millions)

	2009	2010	2011	2012	2013	Total
Borrowing from United States Treasury	$409	$604	$798	$664	$632	**$3,107**
Lease-Purchases[1][2]	120	54	77	235	207	**693**
Projects Funded in Advance	49	105	107	39	9	**309**
Reserve Funding	15	-	30	15	15	**75**
Electric Power Prepayments[3]	-	-	-	-	20	**20**
Total	**$593**	**$762**	**$1,012**	**$953**	**$883**	**$4,203**

(1) Reflects actual capital expenditures funded by the related source, not the amount of the debt (or related liability) by source.
(2) See "—Bonneville's Non-Federal Debt—Bonneville's Transmission Facility Lease-Purchase Program."
(3) See "—Bonneville's Non-Federal Debt—Electric Power Prepayments."

Bonneville's Capital Investment Expectations and Capital Prioritization Process

To meet a variety of needs, Bonneville is forecasting aggregate planned capital expenditures comparable to or larger 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 energy efficiency/electric power conservation program, and (iv) to meet fish and wildlife capital commitments under the Columbia Basin Fish Accords, the applicable Columbia River System biological opinions, and the Willamette River Project Biological Opinion. Bonneville's capital expenditures also include information technology, certain heavy equipment and certain costs related to financing.

During the spring of 2012, Bonneville outlined a general approach and process for prioritizing capital investments. In Fiscal Year 2014, Bonneville has proposed and has received comments from customers on an "Affordability Cap" that would limit Bonneville's average annual capital spending levels over a ten year period to the $855-$940 million range. The Affordability Cap range is based on long-term effects on Bonneville's power and transmission rates, cost structure, financing, and other objectives. While the Affordability Cap if adopted, would set a planning ceiling on capital spending, it would do so without regard to the condition of physical assets or the capacity and other demands that are placed on the power and transmission system. The role of the new investment prioritization process is to determine the optimal investment portfolio within the constraints of the Affordability Cap. The new prioritization process applies to Transmission, Federal System Hydro, Facilities, Information Technology, Security, and other small program investments. The new prioritization process does not apply at this time to investments in Energy Efficiency, Fish and Wildlife and the Columbia Generating Station and to certain investments that Bonneville believes are not within its direct control to determine, such as investments under the Columbia River Fish Mitigation program appropriated to the Corps by Congress.

In connection with developing Bonneville's rate proposal for the Fiscal Year 2016-2017 Rate Period, Bonneville has proposed the capital spending levels shown in the table that follows. These spending levels reflect the preliminary outcome of Bonneville's capital prioritization process.

Forecast Capital Spending by Program and Fiscal Year
(Dollars in millions)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
Transmission	$531	$627	$530	$468	$399	$388	$372	$280	$286	$290	**$4,171**
Fed System Hydro	190	200	224	230	257	282	307	332	349	355	**2,727**
Energy Efficiency	75	92	95	98	101	104	107	110	113	116	**1,010**
Fish and Wildlife	50	52	55	31	19	35	35	34	29	29	**368**
Facilities, Information Technology, Security	119	89	100	67	61	58	53	59	52	54	**714**
AFUDC[(1)]	43	52	63	39	38	45	25	26	27	29	**388**
Total	**$1,009**	**$1,112**	**$1,067**	**$933**	**$874**	**$912**	**$899**	**$841**	**$857**	**$874**	**$9,377**

(1) AFUDC is "Allowance for Funds Used during Construction," a measure of interest on funds borrowed to construct electric utility plant to completion and operation.

The Forecast Capital Spending table above does not include investments projected by Energy Northwest for the Columbia Generation Station. Energy Northwest has developed a long-term capital investment strategy for the Columbia Generation Station in view of a recent 20-year operating license extension, evolving and expected guidance from the Nuclear Regulatory Commission, and other factors. The strategy identified $891 million in additional capital requirements from July 2015 through June 2024. Bonneville expects that new capital needs for the project will be funded with Net Billed Bonds issued by Energy Northwest, the debt service of which will be covered by Bonneville under Net Billing Agreements. See the Official Statement under the heading "ENERGY NORTHWEST—The Columbia Generating Station." The Forecast Capital Spending table above also does not include investments related to the Columbia River Fish Mitigation program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife."

There is substantial uncertainty in forecasting capital program needs. Actual capital spending can differ substantially from forecasts due to various factors including, among other things, changing needs, customer demands and input, expected rate impacts, and changes in expected costs, regulatory requirements, technology, asset prioritization, and the availability of non-capital investment alternatives.

Bonneville's Capital Financing Strategy

Given the large amount of potential Federal System investment described above, and based on current and forecast capital spending levels, and the amount of available United State Treasury borrowing authority, Bonneville estimates that it could reach the ceiling amount of its authority to borrow from the United States Treasury as early as

Fiscal Year 2017, absent the use of Non-Federal Debt and other funding arrangements. In view of this possibility, Bonneville has worked and continues to work with its customers to develop a strategic approach to assure that current capital investment sources described in the table above, including Non-Federal Debt, and borrowing from the United States Treasury, and other means, are sufficient to meet Bonneville's capital program and liquidity needs. Bonneville believes that adherence to the capital strategy will assure that Bonneville will meet capital and financial liquidity needs, through at least Fiscal Year 2023. The capital strategy is predicated in part on an assumption that Bonneville will reserve $750 million of its United States Treasury borrowing capacity to be available for short-term borrowing for liquidity.

Possible Non-Federal Debt Activities in the Near Future

In carrying out its capital financing strategy, Bonneville is planning to or may seek to enter into Non-Federal Debt arrangements in the near future.

Future Lease-Purchases. Bonneville expects that the Port will issue about $200 million of Bonneville-supported lease-purchase bonds and establish a Bonneville-supported $200 million short-term bank facility to fund construction of transmission facilities in calendar year 2014. On July 9, 2014, the Port Board of Commissioners approved a resolution authorizing the execution and delivery of documents related to the $200 short-term bank facility on or before August 31, 2014. The Port has taken no official action to authorize such additional bonds. Bonneville also expects to enter into a short-term lease-purchase arrangement with the Idaho Energy Resources Authority ("IERA"). Bonneville expects that IERA will establish a Bonneville-supported $100 million short-term bank facility to fund construction of transmission facilities. In July 2014, IERA adopted a resolution authorizing such bank loan.

For future years, Bonneville believes that the amount of short- and long-term lease-purchase arrangements and the bank loans and bonds secured thereby could meet about 50 percent of the Federal Transmission System's capital needs. As part of Bonneville's Capital Investment Review process for Fiscal Year 2014, Bonneville forecast that capital expenditures from funds provided under lease-purchase agreements will average approximately $209 million annually over Fiscal Years 2012-2023. Bonneville expects about approximately $209 million per year in short-term bank facilities will be established to fund construction, pending repayment with the proceeds of long-term lease-purchase bonds. Bonneville believes that the aggregate principal amount of short-term, lease-purchase construction bank facilities could equal or exceed $1 billion at any one time. See "—Bonneville's Non-Federal Debt." It is possible that the Port, IERA, or others could enter into such short-term bank facilities and/or issue such publicly-offered bonds.

Possible Additional Net Billed Bonds and Net Billed Project Debt Restructuring. Bonneville expects that Energy Northwest will continue to issue Net Billed Bonds to fund new capital investments for the Columbia Generating Station in the amount of approximately $891 million from July 2015 through June 2024.

In addition, in the past, Bonneville and Energy Northwest have worked together to restructure Net Billed Bond debt to extend the average maturity of the outstanding principal balance of such debt to match more closely the originally expected economic useful lives of the facilities financed thereby. This freed up revenues that Bonneville had collected through its rates to pay down the principal balance of bonds outstanding to the United States Treasury. This had the effect of replenishing Bonneville's United States Treasury borrowing capacity for use for additional investments in the Federal System. Between 2001 and 2009, this program was referred to as "Debt Optimization." Bonneville estimates that Debt Optimization resulted in the prepayment of bonds issued to the United States Treasury and appropriations repayment responsibilities in the amount of approximately $2.5 billion, in aggregate.

In a similar vein, all of the 2014-C Bonds are being issued to extend the final average maturity of debt for Project 1 and Project 3. The purpose is to match the weighted average maturity of Project 1 and Project 3 Net Billed Bond debt more closely to the originally expected economic useful lives of facilities financed by the Project 1 and Project 3 Net Billed Bond debt. This will free up revenues that Bonneville has collected in its power rates and enable it to prepay like amounts of Bonneville's federal appropriations repayment obligations in Fiscal Year 2014. It will also have the indirect effect of restoring some of Bonneville's borrowing capacity with the United States Treasury. Bonneville has asked Energy Northwest to consider undertaking similar Net Billed Bond refinancing actions in the future. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE–Regional Cooperation Debt."

Possible Non-Federal Debt for Bonneville's Region-wide Conservation Resource Acquisition Program. Bonneville is considering whether to seek to meet a large portion of its electric power conservation and energy saving program with transactions involving Non-Federal Debt. Under this form of Non-Federal Debt, Bonneville would enter into resource acquisition agreements in which a third party would issue bonds, the proceeds of which would be used to fund energy conservation measures. The bonds would be secured by Bonneville's commitment to provide conservation acquisition payments in return for associated energy savings. Depending on a variety of factors, it is possible that this type of arrangement could fund $70 million or more per year of conservation investments, beginning in Fiscal Year 2016. Bonneville has entered into similar conservation resource arrangements in the past. See "—Bonneville's Non-Federal Debt." At Bonneville's request, Energy Northwest is considering whether it would act as the third party in the foregoing arrangement.

Possible Additional Electric Power Prepayments. While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use this form of Non-Federal Debt to meet some of its capital funding needs. See "—Bonneville's Non-Federal Debt."

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. 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.

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 Net Billed Projects. 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. 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. 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. 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 2013 were $193 million, $123 million, and $28 million, respectively.

Bonneville believes that the direct funding approach has increased 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. One result of direct funding obligations 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 approximately $589 million to $1.1 billion 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 2019. 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 the United States Treasury would be payable by Bonneville from "net proceeds." See "—Order in Which Bonneville's Costs Are Met."

Order in Which Bonneville's Costs Are Met

Bonneville is required to establish rates sufficient to make, and makes, 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 2013 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $692 million in Fiscal Year 2013, approximately $56 million was for the amortization ahead of schedule of certain federal appropriations repayment obligations to the United States Treasury. Bonneville plans to make similar advance amortization payments to the United States Treasury in Fiscal Year 2014. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE–Regional Cooperation Debt."

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 2014-C Bonds; payments, if any, under the 1989 Letter Agreement; payments under the Direct Pay Agreements; and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements securing the 2014-C Bonds, payments, if any, under the 1989 Letter Agreement, payments under the Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS" and "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Direct Pay Agreements," and see "—Direct Payment 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. 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. For a description of the Net Billing Agreements see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS." (Bonneville and Energy Northwest have entered into Direct Pay Agreements under which Bonneville pays the costs of the Net Billed Projects on a current cash basis thereby reducing the use of net billing to meet the costs of the Net Billed Projects. See "—Direct Pay Agreements").

Bonneville also has obligations to reduce future amounts receivable from certain power customers that have prepaid for electric power, see "—Bonneville's Non-Federal Debt—Electric Power Prepayments," and from certain transmission customers that have provided lump sum payments to Bonneville for it to construct or install certain transmission facilities necessary to provide transmission service to the customers. The electric power prepayments involve the recognition (as credits) of the prepayments in future electric power bills by Bonneville. The credits for prepaid power will be approximately $30.6 million per fiscal year through Fiscal Year 2028. Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments was $41 million in Fiscal Year 2013 and will be $40 million in Fiscal Year 2014. The foregoing credits have the effect of reducing Bonneville's future cash revenue from the participating customers, and will reduce in the future the amount of cash in the Bonneville Fund that would otherwise be available to meet Bonneville's cash payment obligations, including under the Net Billing Agreements, the 1989 Agreement, or the Direct Pay Agreements.

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 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 2013, approximately $693 million in Total Financial Reserves were derived from Power Services' rates and operations and $579 million in Total Financial Reserves 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-derived reserves so used. Similarly, if Bonneville were to use Power Services-derived reserves to pay Transmission Services' costs, use of the Power Services' reserves would be treated as an obligation of Transmission Services, with the requirement that Transmission Services replenish any amounts of Power Services-derived reserves so used.

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 TPP. Exceptions to established policies must be cleared by the TRMC before execution.

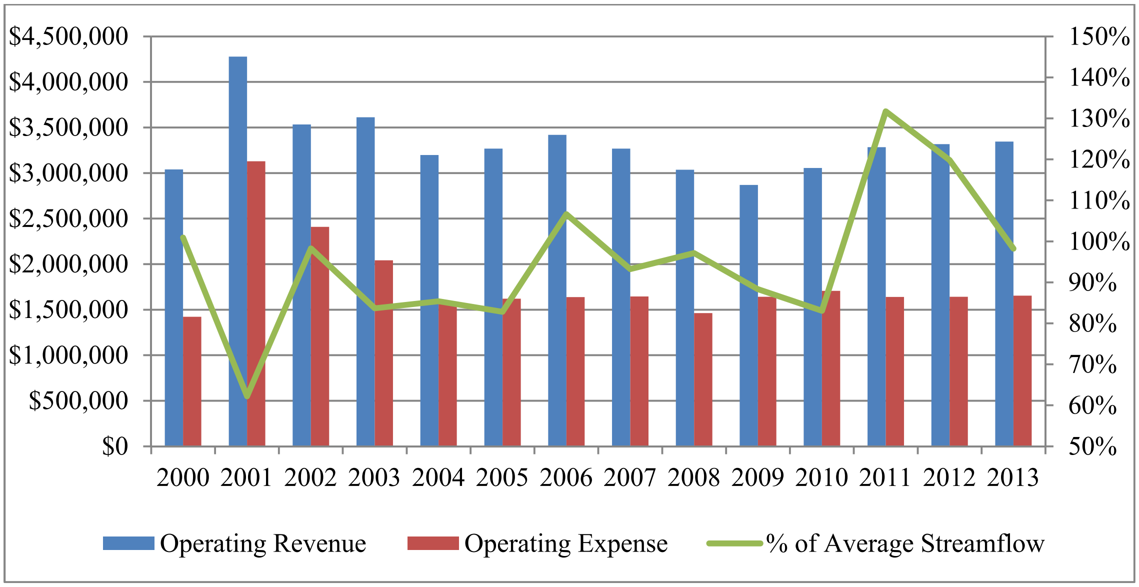
Bonneville engaged in and concluded a pilot hedging program in 2011 involving exchange-traded, power-related financial swaps that do not require physical delivery. Due to changing market conditions in the over-the-counter ("OTC") physical delivery energy markets and based on the successful pilot program, Bonneville's TRMC approved in 2012 a permanent and ongoing financial hedging program using power futures that do not require physical delivery. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—2010 Dodd-Frank Act and Bonneville." Such transactions 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 delivery power trading contract obligations, including OTC physical delivery electric power transactions.

Historical Federal System Operating Revenue and Operating Expense Compared to Historical Stream Flows

Streamflow is an important variable in Bonneville's financial performance because, in effect, it is the fuel for the hydroelectric facilities of the Federal System. The availability of hydroelectric generation affects Bonneville's purchased power costs. In periods of abundant hydroelectric generation Bonneville can avoid making 'balancing' short-term power purchases to match loads. In periods of low hydroelectric generation, Bonneville's purchased power expense can increase to make such balancing purchases. Conversely, in periods of abundant hydroelectric generation Bonneville can obtain additional revenue from marketing seasonal surplus (secondary) energy while in periods of low hydroelectric generation, such revenue can diminish. Bonneville's ratemaking, power and resource planning, financial operations, power operations, power marketing and risk management functions all take hydroelectric variability into account in their operations and have been doing so, in effect, since Bonneville's creation.

The following chart plots Bonneville's annual operating expense and operating revenues against Federal System streamflows in the same year. The streamflow data for the relevant year are expressed as a percentage of historical average streamflows. Bonneville believes that the relative stability of operating expense and operating revenue over a wide variety of annual stream flows, particularly since 2002, reflects Bonneville's accommodation of the potential variability of streamflows in virtually all of Bonneville's major functions.

Historical Federal System Operating Revenue and Operating Expense
Compared to Historical Stream Flows
($ in thousands)



In the preceding table, the streamflow data are based on the Federal System's Operating Year (August 1 – July 30) and the financial information is based on Bonneville's Fiscal Year (October 1 – September 30).

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2011 through 2013 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 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 certain operation and maintenance costs of the Fish and Wildlife Service.

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Federal System Statement of Revenues and Expenses
(Unaudited)

As of Sept. 30 – Dollars in thousands	2013	2012	2011
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities [(1)]	$1,829,283	$1,833,277	$1,762,498
Direct Service Industrial Customers	101,611	108,628	103,241
Northwest Investor-Owned Utilities	73,142	65,668	154,569
Sales outside the Northwest Region [(2)]	434,431	443,022	466,493
Book-outs [(3)]	(66,587)	(61,972)	(92,198)
Total Sales of Electric Power	2,371,880	2,388,623	2,394,063
Transmission [(4)]	857,696	821,232	775,770
Fish Credits and other Revenues [(5)]	116,705	107,995	114,401
Total Operating Revenues	3,346,281	3,317,850	3,284,774
Operating Expenses:			
Bonneville O&M [(6)]	960,622	965,419	914,457
Purchased Power [(3)]	154,173	143,119	177,953
Corps, Reclamation, and Fish & Wildlife O&M [(7)]	344,593	297,873	280,349
Non-Federal entities O&M — net billed [(8)]	297,485	283,745	311,948
Non-Federal entities O&M — non-net billed [(9)]	39,339	46,153	42,788
Total Operation and Maintenance	1,796,212	1,736,309	1,727,495
Net billed Debt Service	717,296	643,527	608,171
Non-net billed Debt Service	16,017	16,153	16,801
Non-Federal Projects Debt Service [(10)]	733,313	659,680	624,972
Federal Projects Depreciation	429,717	389,097	393,502
Residential Exchange [(11)]	201,933	203,712	184,764
Total Operating Expenses	3,161,175	2,988,798	2,930,733
Net Operating Revenues	185,106	329,052	354,041
Interest Expense:			
Appropriated Funds	236,805	232,364	245,106
Long-term debt	155,500	120,686	135,141
Capitalization Adjustment [(12)]	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(37,529)	(45,845)	(42,983)
Net Interest Expense [(13)]	289,871	242,300	272,359
Net Revenues/(Expenses)	$(104,765)	$86,752	$81,682
Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	9,994	10,819	11,042

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(1) This customer group includes Preference Customers (municipalities, public utility districts, and 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 recorded in Fiscal Year 2013 were $76.5 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 book-outs 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 approximately $85.1 million, $76.9 million, and $84.1 million in Fiscal Years 2011, 2012, and 2013 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."

(6) Bonneville O&M expenses include the expenditures for the Federal Transmission System, and for Bonneville's operation and maintenance, power marketing, and 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 Net Billed 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 "Management Discussion of Operating Results." Bonneville's payments to Regional IOUs with respect to the Residential Exchange Program for Fiscal Year 2012 through Fiscal Year 2028 were established under the 2012 Residential Exchange Program Settlement Agreement, dated July 26, 2011. In Fiscal Year 2013, the Residential Exchange Program payments were $182.1 million. In Fiscal Year 2013, Bonneville also provided refunds in an aggregate amount of $76.5 million to qualifying Preference Customers for overpayments ("Refund Amounts") Bonneville made to Regional IOUs for the period July 1, 2001, through September 30, 2011, under the original Residential Exchange Program Settlement Agreements, as thereafter amended and supplemented, that were invalidated by the Ninth Circuit Court in May 2007. Bonneville recognizes a refund for Refund Amounts recovered from Regional IOUs in the rate setting process and returned to Preference Customers and will do so through Fiscal Year 2019, at which time all overpayments will be fully recovered. 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 appropriation repayment obligations under a federal law enacted in 1996.

(13) Lease-Purchase 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 2013

In Fiscal Year 2013, Bonneville made its scheduled United States Treasury payments on time and in full for the 30th consecutive year. Bonneville finished Fiscal Year 2013 with Total Financial Reserves of $1.27 billion, which is an increase of approximately 25 percent from the prior fiscal year. A major factor in the increase in financial reserves was the receipt in April 2013 by Bonneville of $340 million in power prepayments from certain Preference Customers, which in return receive a discount and a reduction in their future power payment obligations to Bonneville. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt." Total Financial Reserves are composed of cash, cash equivalents, and special investments held in the Bonneville Fund, and deferred borrowing from the United States Treasury. Total Financial Reserves are amounts available to meet Bonneville's current expenditure needs and are affected by numerous factors including 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. Total Financial Reserves are a measure of financial resources that can be used on short order to meet current obligations.

For Fiscal Year 2013, Federal System net revenues were negative $105 million, a decrease of approximately $192 million from net revenues of $87 million in Fiscal Year 2012.

For Fiscal Year 2013, Power Services and Transmission Services consolidated gross sales increased by approximately $600,000 from the prior fiscal year. Power Services' gross sales decreased $12 million, or less than one percent, primarily due to two key factors:(i) firm power sales decreased $17 million, or one percent, in Fiscal Year 2013 compared to Fiscal Year 2012; (ii) seasonal surplus (secondary) sales increased $5 million, or one percent, in Fiscal Year 2013 compared to Fiscal Year 2012 due to higher market prices that offset decreased streamflows compared to the prior year. 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 through July 2013 runoff volume at The Dalles Dam was 98 MAF. The full Fiscal Year 2013 volume finished at 130 MAF, a decrease from 159 MAF in Fiscal Year 2012, and close to the historical average of 133 MAF.

Transmission Services gross sales increased $13 million, or two percent, mainly due to increases in Variable Energy Resource Balancing Service ("VERBS") and long-term Point-to-Point Long-Term sales (a type of transmission service that uses a single transmission path between two points). VERBS is an ancillary service that transmission users are required to obtain to help conform to reliability standards. Point-to-Point Long-Term is firm transmission services of one year or more delivering federal and non-federal power across the Federal Transmission System. VERBS sales increased by $7 million due to additional installed wind generation facilities. Point-to-Point Long-Term sales increased by $5 million due to increased Conditional Firm sales and the effect of certain network service that was committed to by Bonneville in Fiscal Year 2012.

Transmission miscellaneous revenues increased by $24 million, or 78 percent, mainly due to reimbursable activity from other federal agencies for assistance Bonneville provided in the aftermath of Hurricane Sandy and the termination/expiration of certain transmission service by Bonneville which was provided on comparatively favorable terms to the related customers (referred to by Bonneville as "Precedent Transmission Service Agreements").

Operating expense increased approximately $172 million in Fiscal Year 2013 from Fiscal Year 2012. Operations and maintenance increased $47 million, or three percent, from the prior fiscal year primarily because (1) Reclamation costs increased by $38 million, primarily due to additional non-routine extraordinary maintenance work at Grand Coulee Dam, (2) Columbia Generating Station costs increased $38 million because of biennial refueling and maintenance, (3) transmission maintenance costs increased $11 million due to increased reliability compliance activities and upgrades to Federal Transmission System communication systems, and (4) transmission reimbursable cost increased $7 million primarily as a result of Hurricane Sandy East Coast emergency response activity. These increases were offset in part by receipt of $28 million from the United States government in settlement of its failure to take spent nuclear fuel into permanent storage (the amounts were initially paid to EWEB as part owner of the terminated Trojan nuclear facility, and from whom Bonneville acquired project capability under net billing agreements similar to the Net Billing Agreements with Energy Northwest). Bonneville also reduced spending on long-term and renewable generation projects by $7 million, transmission marketing and business support by $7 million, and transmission acquisition and ancillary services by $5 million.

Purchased power expense increased $11 million, or eight percent, from the prior fiscal year. The increase in purchased power was driven mainly by lower year-over-year hydroelectric generation and reduced output of the Columbia Generating Station due to the scheduled refueling and maintenance outage in Fiscal Year 2013. Net interest expense for Fiscal Year 2013 increased $48 million, or 20 percent, compared to Fiscal Year 2012, primarily due to an increase of $25 million from increased borrowings necessary to finance Power Service's-related construction projects and from increased lease-purchases of transmission facilities.

Bonneville's Use of Adjusted Net Revenues as a Financial Performance Metric. In Fiscal Year 2013, Bonneville commenced utilizing and reporting a new financial metric, "Adjusted Net Revenues." While the Adjusted Net Revenues (or, "ANR") metric is not a measure in accordance with GAAP and is unaudited, Bonneville management believes the use and reporting of ANR assists in reflecting Bonneville's financial performance for day-to-day operations in applicable fiscal years. The ANR metric is net revenues after removing the effects of certain debt management actions from prior fiscal years. These debt management actions were implemented to replenish available United States Treasury borrowing capacity by extending into the future the repayment dates of debt for the Net Billed Projects. The resulting reductions in intervening debt payments (in the period between the dates the Energy Northwest debt was initially due to be repaid and the dates that such refinanced debt was re-set to be repaid) resulted in funds becoming available to pay down the aggregate principal amount of Bonneville's then-outstanding United States Treasury debt. This prior program is referred to as Debt Optimization.

Under GAAP, Energy Northwest debt expense is recorded over the term of the related outstanding debt. With a lower Energy Northwest debt expense due to the debt management actions, Debt Optimization resulted in higher net revenues than otherwise would have been reported in the affected fiscal years absent the debt management actions. These debt management actions led to the replenishment of available United States Treasury borrowing capacity as a result of extending the average maturities of debt for the Net Billed Projects to more closely match their originally expected useful lives. As the Energy Northwest debt that was issued for the refinancing under Debt Optimization reaches maturity, as is now occurring, the converse of the original effects of Debt Optimization on financial reporting is also occurring: non-federal projects' expense is higher than, and Federal System net revenues are lower than, would have been the case without Debt Optimization. The effects on net revenues (a GAAP-recognized metric) in Fiscal Year 2013 of the prior debt management actions were negative $161 million (this is reflected as "Adjustment for Debt Service Reassignment" in the audited Financial Statements of the Federal System included as Appendix B-1 to the Official Statement). The effects of these past debt management actions are not considered to be related to ongoing Federal System operations, and therefore management has determined that the ANR metric is a better representation of Federal System financial performance for the period.

Adjusted Net Revenues were $56 million in Fiscal Year 2013. By contrast, as noted immediately above, net revenues were negative $105 million in Fiscal Year 2013.

Reserves Available for Risk. For ratemaking purposes, Bonneville uses a financial metric it refers to as RAR as a measure of reserves. See "—Bonneville's Financial Reserves." While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations.

The RAR metric is an important factor in Bonneville's ratemaking. In establishing rates, Bonneville forecasts numerous variables including costs, revenues, and the availability of financial liquidity resources such as short-term expense borrowing from the United States Treasury and expected RAR as of the beginning of the applicable rate period, and weighs numerous financial risks. This consideration yields a TPP. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments." Depending on numerous variables, assumptions and forecasts, Bonneville may establish rates that seek to increase (or decrease) RAR for the relevant business line in the applicable rate period in amounts that Bonneville believes are sufficient to meet its TPP policy. All of the Total Financial Reserves in the Bonneville Fund are available to meet all of Bonneville's costs without regard to whether they were derived from Transmission Services' operations or Power Services' operations and without regard to Bonneville's aggregate RAR or the business lines' respective RAR levels. See "—Bonneville's Financial Reserves" and "—Order in Which Bonneville's Costs Are Met."

Bonneville determines RAR for both Power Services operations and Transmission Services operations. At the end of Fiscal Year 2013, RAR for Power Services operations was $182 million, a decline of 16 percent from the prior fiscal year, and RAR for Transmission Services operations was $459 million, a decline of six percent from the prior fiscal year. Aggregate Bonneville RAR was $641 million, a decline of nine percent from the prior fiscal year. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Reserves."

Fiscal Year 2012

For Fiscal Year 2012, Federal System net revenues were $87 million, an increase of $5 million from net revenues of $82 million in Fiscal Year 2011.

For Fiscal Year 2012, Power Services and Transmission Services consolidated gross sales increased $15 million, or less than one percent, from the prior fiscal year. Power Services gross sales decreased $36 million, or slightly over one percent due to several key factors. Firm power sales decreased $31 million, or slightly over one percent, in Fiscal Year 2012 compared to Fiscal Year 2011. The Tiered Rates structure commenced in Fiscal Year 2012 and revenues from the provision of load shaping service were lower than expected. The load shaping product is a load-following product that provides customers with the ability to deviate from their forecast purchases from Bonneville. With this product, the customer pays only for the amount of power delivered, at the applicable rate. Bonneville did not have a specific load shaping rate prior to Fiscal Year 2012, but in establishing rates it assumed a level of revenue from load shaping that did not materialize because Preference Customers' loads were lower than forecast. Seasonal surplus (secondary) sales decreased $10 million, or two percent, in Fiscal Year 2012 compared to Fiscal Year 2011 due to lower market prices. The effect of increased generation of seasonal surplus (secondary) was more than offset by lower market prices in Fiscal Year 2012 compared to Fiscal Year 2011. River runoff in the January 2011 through July 2011 runoff period was the ninth highest on record, measuring 129 MAF at The Dalles Dam. For the entire Fiscal Year 2012, the Federal System experienced the thirteenth highest water year on record at 159 MAF at The Dalles Dam, a decrease from 175 MAF in Fiscal Year 2011, although still above the historical average of 133 MAF.

Transmission Services gross sales increased $51 million, or approximately seven percent, due in part to a $20 million increase in revenues from long-term Point-to-Point sales and $20 million due to a rate increase for providing certain power system operating reserves, which is an ancillary service.

Operating expense increased $58 million in Fiscal Year 2012 from Fiscal Year 2011. Operations and maintenance increased $63 million, or four percent, from the prior Fiscal Year. Operating expense changes from the prior Fiscal Year were: (1) $29 million increase in Transmission Services operations and maintenance; (2) $28 million increase in Fish and Wildlife Program expense; (3) $20 million increase in Corps and Reclamation operations and maintenance; (4) $19 million increase in Residential Exchange Program expense: and (5) $16 million increase in other Bonneville operating expense. The foregoing expense increases were partially offset by a $20 million expense decrease for the Columbia Generating Station because 2012 was not a refueling year (by contrast, Fiscal Year 2011 was a refueling year). In addition certain transmission assets were impaired, resulting in a $21 million impairment charge. Gross purchased power expense decreased $35 million, or 20 percent, for Fiscal Year 2012 when compared to Fiscal Year 2011 because of higher total generation (primarily because of increased generation at Columbia Generating Station) which reduced the amount of power purchases to meet load, and lower market prices for power purchases. Non-federal projects debt service increased $35 million, or six percent, primarily caused by an increase in debt repayments for Energy Northwest Project 1 and Project 3 in accordance with debt repayment schedules.

Net interest expense for Fiscal Year 2012 decreased $30 million, or 11 percent, compared to Fiscal Year 2011, primarily due to a decrease of $21 million in interest expense from a reduction of costs allocated from borrowings for continued expansion of transmission construction, conservation, and Fish and Wildlife programs.

Fiscal Year 2011

For Fiscal Year 2011, net revenues were $82 million, an increase 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, primarily due to several key factors. Firm power sales increased $72 million, or four percent, in Fiscal Year 2011 compared to Fiscal Year 2010 due to higher power sales revenue from Preference Customers resulting from an increase in the amount of power sold. For Fiscal Year 2011, Power Services received increased revenues from DSI sales because 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. 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.

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. Other key operating expense changes from the prior fiscal year were increases of (i) $23 million in Transmission Services operations and maintenance, $22 million in Fish and Wildlife Program, and $14 million for other agency expenses. Fish and wildlife increases were driven by changes in the Council Program and in connection with the 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, 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 Energy Northwest's 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."

Statement of Non Federal Debt Service Coverage

The "Statement of Non-Federal 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 Debt Service Coverage Ratio"), which demonstrates how many times total non-federal project debt service is covered by net funds available for non-federal project debt service. Net funds available for non-federal project debt service is defined as total operating revenues less operating expenses. 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 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 under the Net Billing Agreements.

Statement of Non Federal Debt Service Coverage and United States Treasury Payments (unaudited)

As of Sept. 30 – Dollars in thousands	**2013**	**2012**	**2011**
Total Operating Revenues	$3,346,281	$3,317,850	$3,284,774
Less: Operating Expenses[1]	1,653,552	1,642,148	1,640,415
Net Funds Available to meet Non-Federal Debt Service Obligations	1,692,729	1,675,702	1,644,359
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects[2]	733,313	659,680	624,972
Lease-Purchase Program[3]	28,949	25,451	23,872
Electric Power Prepayments [4]	12,750	-	-
Total Non-Federal Debt Service Obligations	775,012	685,131	648,844
Revenue Available for Treasury	917,717	990,571	995,515
Amount Allocated for Payment to Treasury[9]:			
Corps and Reclamation O&M[5]	344,593	297,873	280,349
Net Interest Expense[6]	289,871	242,300	272,359
Lease-Purchase Program[3]	(28,949)	(25,451)	(23,872)
Electric Power Prepayments[4]	(7,653)	-	-
Capitalization Adjustment[7]	64,905	64,905	64,905
Allowance for Funds Used During Construction [8]	15,058	28,175	25,022
Amortization of Federal Principal	224,540	393,110	409,528
Total Amount Allocated for Payment to Treasury[9]	902,365	1,000,912	1,028,291
Revenues Available for Other Purposes[10]	$15,352	$(10,341)	$(32,776)
Non-Federal Debt Service Coverage Ratio[11]	2.2x	2.4x	2.5x
Non-Federal Debt Service Plus Operating Expense Coverage Ratio[12]	1.4x	1.4x	1.4x

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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 (principal and interest) for generating resources acquired by Bonneville under Net Billing Agreements or other capitalized contracts. Non-net billed debt service amounted to $16.8 million, $16.2 million, and $16 million for Fiscal Years 2011, 2012, and 2013 respectively.

(3) Includes related debt service amounts with respect to certain transmission facilities that Bonneville is leasing under capitalized lease-purchase agreements. In Fiscal Year 2013, the aggregate debt service amount of $28.95 million represents interest expense only.

(4) In Fiscal Year 2013, Bonneville received $340 million from certain Preference Customers as one-time prepayments of portions of their future power bills through Fiscal Year 2028. In return the customers will receive discounted credits in future power bills. The aggregate amount of the credits is $2.55 million per month through Fiscal Year 2028. In Fiscal Year 2013, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $12.75 million. Of this amount, $7.65 million is accounted for as Net Interest Expense and $5.1 million is accounted for as the repayment of principal. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments."

(5) 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 2011, 2012, and 2013. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(6) The interest portion related to the Lease-Purchase Program and Electric Power Prepayments are included in their entirety in Net Interest Expense, as reported in the audited financial statements of the Federal System. 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), with the presentation of Revenue Available for United States Treasury in this Table, Net Interest Expense is reduced by the interest portions of the Lease-Purchase Program payments and Electric Power Prepayments. Amounts shown are calculated on an accrual basis. For clarity, none of the related interest expense for the Lease-Purchase Program and for Electric Power Prepayments is reflected in Allowance for Funds Used During Construction.

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

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

(9) In contrast to the "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2011, 2012, and 2013 were $830 million, $886 million, and $692 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."

(10) 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).

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

$$\frac{\text{Total Operating Revenues-Operating Expense (Footnote 1)}}{\text{Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments}}$$

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

$$\frac{\text{Total Operating Revenues}}{\text{Operating Expense (Footnote 1) + Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments}}$$

Management Discussion of Unaudited Results for the Nine Months Ended June 30, 2014

For the nine months ended June 30, 2014, Power Services' and Transmission Services' consolidated gross sales increased $200 million, or eight percent, from the comparable period a year earlier, as reported in the Combined Statements of Revenues and Expenses. Power Services' gross sales increased $126 million, or seven percent. Power sales made at PF Preference Rates increased by $29 million, or five percent, for the nine months ended June 30, 2014, compared to the nine months ended June 30, 2013, primarily due to an increase in PF Preference Rates, which took effect beginning October 1, 2013, and higher Preference Customer utility peak loads as a result of colder than average temperatures in October, December and February. Seasonal surplus (secondary) power sales, net of book-outs, increased $32 million, or ten percent, due to increased streamflows and higher market prices, partially offset by reduced turbine capacity for scheduled maintenance at Grand Coulee Dam.

Transmission Services' gross sales increased $74 million for the nine months ended June 30, 2014, or 12 percent, compared to the nine months ended June 30, 2013 due primarily to the commencement of higher transmission rate levels for certain types of transmission and ancillary service.

Operations and maintenance expense decreased $22 million, or two percent, for the nine months ended June 30, 2014, from the comparable period a year earlier. Columbia Generating Station costs decreased $52 million reflecting a decrease from the higher level of expenses arising from maintenance and biennial refueling in Fiscal Year 2013. The decrease was partially offset by an increase of $30 million for Federal System hydroelectric project maintenance and for transmission engineering and operations.

Purchased power expense, net of book-outs, increased $36 million, or 28 percent, for the nine months ended June 30, 2014, from the comparable period a year earlier. The increase in purchased power was driven mainly by below average streamflows from October through early February and reduced turbine capacity at Grand Coulee Dam due to scheduled maintenance.

Non-federal projects debt service decreased $284 million, or 53 percent, for the nine months ended June 30, 2014, from the comparable period a year earlier. Consistent with a new regional cooperation debt refinancing to manage Energy Northwest debt, the repayment of certain Energy Northwest debt will be made with the proceeds of the 2014-C Bonds. As a result of these Energy Northwest debt refinancing actions, amounts otherwise collected in Bonneville's current Power Services rates will not be needed to fund the Energy Northwest related principal payments as originally expected and as were included for recovery in rates for payment in Fiscal Year 2014. Instead, these amounts will be used to repay, before their maturity dates, like amounts of Bonneville's higher interest rate federal appropriations repayment obligations. Bonneville and Energy Northwest determined in June 2014 to seek to refinance and restructure $321 million of the debt issued by Energy Northwest for its Projects 1 and 3 to extend the average weighted maturity of such debt to more closely match the related facilities' original expected useful lives.

In June 2014 Energy Northwest entered into a short-term line of credit to repay the $321 million of maturing debt due on July 1, 2014. The line of credit will be repaid with the proceeds of the 2014-C Bonds. While these actions are cash flow neutral, they affect reported expenses because principal payments of Energy Northwest debt are included in operating expenses as non-federal projects expense with a corresponding reduction to the related regulatory assets. In connection with these actions, Bonneville's Administrator clarified prospective rate setting principles to specify that the debt service on the long-term refinancing bonds that Energy Northwest issues, as described above, will be fully recovered in Bonneville's future rates. Therefore, in June 2014 Bonneville reduced reported debt service expense for Energy Northwest's Projects 1 and 3 by $321 million, which increased the applicable regulatory assets and resulted in higher net revenues than would have otherwise been reported.

Depreciation and amortization expense increased $14 million, or four percent, for the ninth months ended June 30, 2014, when compared to the same period for Fiscal Year 2013, primarily due to higher transmission and generation completed plant. Net interest expense decreased $21 million, or ten percent, for the nine months ended June 30, 2014, from the comparable period a year ago due to increased borrowing necessary to finance Federal System hydroelectric project investments and increased lease-purchases of transmission facilities. In the second quarter of Fiscal Year 2014, Bonneville extinguished $323 million of outstanding United States. Treasury bonds prior to maturity and reissued $284 million of shorter duration bonds at lower rates of interest, resulting in a gain of $36 million, which decreased interest expense.

See Appendix B-2—"FEDERAL SYSTEM UNAUDITED REPORT FOR THE NINE MONTHS ENDED JUNE 30, 2014." For information regarding Bonneville's Fiscal Year 2014 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2014 Expectations."

Bonneville's Financial Reserves

For cash management purposes, Bonneville tracks Total Financial Reserves (cash, investments in United States Treasury market-based special securities and deferred borrowing), which are available to meet Bonneville's current expenditure needs. (The Total Financial Reserves metric is not a measure in accordance with GAAP and is unaudited.) While Total Financial Reserves can be used at any time to meet obligations, Bonneville does not use this metric in establishing rates. Rather Bonneville focuses on RAR. The RAR metric represents amounts in, or reliably available to, the Bonneville Fund which are generated through normal operations and excludes deposits from third parties, capital funds drawn in advance, borrowings for expenses and other amounts deemed by Bonneville not to be available for risk. These amounts are used in rate case planning for risk mitigation providing a liquidity buffer should Bonneville cash flow decline or turn negative for any significant period of time. These amounts form the basis for Transmission Services' and Power Services' rate case deliberations in determining TPP and for liquidity planning purposes. Thus, the RAR metric measures reserves (or retained amounts) derived from operations. While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations. See "—Management Discussion of Operating Results—Fiscal Year 2013."

As of the end of Fiscal Year 2013, Bonneville had $641 million in RAR and a $750 million short-term credit facility (available to meet certain expenses) with the United States Treasury with no outstanding balance. The RAR balances and the short-term borrowing facility combine to provide a cushion of liquidity for Bonneville to meet its costs in situations where revenues and expenses deviate from rate case assumptions. To achieve an adequately high TPP in ratemaking, Bonneville focuses on RAR. Bonneville's rates may seek to increase RAR for the relevant business line to amounts sufficient to meet Bonneville's 95 percent TPP policy. In some years, Bonneville's rate proposals may assume a lower RAR, provided that the TPP policy is met. For a brief discussion of TPP, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments." For a discussion of expected RAR in Fiscal Year 2014, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2014 Expectations."

One metric that Bonneville uses to measure the amount of liquidity relative to its ability to meet operating expenses is "days liquidity on hand." Bonneville measures this using the following equation: (i) RAR plus Available United States Treasury Short-Term Facility ($750 million) divided by (ii) Operating Expenses divided by 360. The information is unaudited.

Bonneville's Fiscal Year-End Financial Reserves
Fiscal Years 2009-2013
($ in millions)

Fiscal Year	Total Financial Reserves	Reserves Available for Risk	U.S. Treasury Short-Term Line	Days Liquidity on Hand[(1)]
2009	1,363	1,068	750	399
2010	1,114	839	750	335
2011	1,006	747	750	329
2012	1,022	704	750	319
2013	1,272	641	750	303

(1) The calculation of Days Liquidity on Hand is (RAR + United States Treasury Short-Term Line) / (Operating Expenses / 360).

BONNEVILLE LITIGATION

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

Columbia River ESA Litigation

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 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 CWA. 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.

In September 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. In May 2010, NOAA Fisheries finalized a "2010 Supplemental Columbia River System Biological Opinion" to supplement the existing 2008 Columbia River System Biological Opinion and to incorporate the Management Plan. In August 2011, the Oregon Federal District Court upheld the 2010 Supplemental Columbia River System Biological Opinion through 2013; however, the court ordered NOAA Fisheries to issue a new or supplemental Columbia River System Biological Opinion for the calendar years 2014 through 2018 and identifying specific, verifiable mitigation plans beyond 2013 and providing better scientific support for the conclusion that the related measures will avoid jeopardy than was provided for such period in the 2010 Supplemental Columbia River System Biological Opinion.

NOAA Fisheries issued the 2014 Columbia River System Supplemental Biological Opinion and filed a notice of completion of remand in conformance with the court's order. In February of 2014 Bonneville, the Corps and Reclamation each signed a record of decision to implement the biological opinion. On May 27, 2014, American Rivers and other plaintiffs filed a petition in the Ninth Circuit Court of Appeals challenging Bonneville's record of decision. On June 17, 2014, the National Wildlife Federation and other plaintiffs filed a motion for leave to file a supplemental complaint in the Oregon Federal District Court alleging that the 2014 Columbia River System Supplemental Biological Opinion violated certain provisions of the ESA, NEPA, and Administrative Procedures Act. As with the petition against Bonneville in the Ninth Circuit, the claims are similar to previous challenges of past biological opinions, with the exception of one additional claim under NEPA challenging the federal agencies' reliance on prior NEPA documents. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

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 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 approximately $75 million in foregone power revenues in Fiscal Year 2005 when compared to the revenues that would have accrued had spill occurred as set forth under the 2004 Biological Opinion. For hydro-operations from 2006-2013, the federal agencies proposed a spill program that somewhat reduced the potential for foregone power revenues when compared to court-ordered spill in 2005, and the court approved the proposals. The 2014 Columbia River System Supplemental Biological Opinion continues, with slight variations, the river operations program under the 2010 Supplemental Columbia River Biological Opinion. In light of the issuance of the 2014 Columbia River System Supplemental Biological Opinion and completion of the court-ordered remand, no request for court approval is being made for 2014 river operations.

DSI Service Litigation

Bonneville's power sales to DSIs have been the subject of litigation since 2000. The only extant litigation is currently pending in the Ninth Circuit Court. The issues in the case pertain to contracts originally intended to provide power sales service by Bonneville to two current DSIs (Alcoa and Port Townsend Paper) and one DSI not currently taking service from Bonneville (Columbia Falls Aluminum Corporation) for portions of the period Fiscal Years 2007-2011. In 2007, two Preference Customers, an association of Preference Customers and an association representing industrial customers of Preference Customers (collectively, the "DSI Service Petitioners") filed legal challenges in the Ninth Circuit Court seeking to set aside Bonneville's entry into the contracts and requesting that the Ninth Circuit Court direct Bonneville to take action to recoup from the DSIs approximately $159 million in amounts paid by Bonneville in lieu of physical power deliveries to the DSIs under the contracts. In 2008, the Ninth Circuit Court partially invalidated the contracts, but denied the DSI Service Petitioners' request for relief. However, the court remanded the recoupment matter to Bonneville for further consideration. On remand, Bonneville considered:

1. Whether a damage waiver provision in the subject Alcoa contract (whereby both Bonneville and Alcoa relinquished any claims in the event that a court were to render the agreement unenforceable) remained enforceable and was severable from other terms of the contract in light of the court's partial invalidation; and

2. Whether, in the absence of a damage waiver provision, Bonneville had a valid basis to pursue a claim against the DSIs for the restitution of benefits provided under the partially invalidated contracts and whether the claims, if any, would have a reasonable prospect of success.

In 2011, Bonneville issued an administrative determination and record of decision concluding that the damage waiver is both enforceable and severable, and that there is no reasonable basis upon which to predicate a claim for restitution from the DSIs. In response to Bonneville's determination, the DSI Service Petitioners challenged the determination and filed briefs with the Ninth Circuit Court arguing that Bonneville violated the Appropriations Clause of the United States Constitution in making the contested payments to the DSIs and Bonneville has an absolute duty to undertake collection efforts and pursue litigation in such instances, if necessary. Bonneville's position is that no violation of the Appropriations Clause has occurred and there is no support for the proposition it has an absolute duty to initiate collection efforts and pursue litigation against the DSIs for recovery of payments regardless of the circumstances. The matter has been briefed and oral argument was held May 9, 2013. The litigants await a decision.

Bonneville's power sales to Port Townsend and Alcoa are now governed by contracts for sale and delivery of power at the IP Rate, in the amounts of 12.5 annual average megawatts and 300 annual average megawatts, respectively. The contracts end near the end of calendar year 2022. The 90 day period permitted for filing challenges to Bonneville's decisions to enter into such DSI contracts has elapsed without legal challenge. Any future effort to initiate such a challenge would be time-barred.

In January 2014, Bonneville proposed to amend Port Townsend's current ten year contract to increase its contract demand by an additional three annual average megawatts, effective June 1, 2014. Bonneville would sell this additional energy to Port Townsend at the IP rate.

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 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. These petitions have been stayed pending resolution of litigation over the 2012 Residential Exchange Program Settlement. See "-Residential Exchange Program Litigation."

In July 2011, Bonneville issued a Record of Decision at the conclusion of its 2012 Power and Transmission Rate Proposal (the "2012 Rates ROD"). On December 31, 2012, FERC granted final approval of Bonneville's rates for Fiscal Years 2012-2103. In March 2013, Clatskanie, Georgia Pacific, and the Industrial Customers of Northwest Utilities ("ICNU") filed petitions for review with the Ninth Circuit Court challenging certain decisions in the 2012

Rates ROD regarding Bonneville's treatment of "contracted for or committed to" loads, a specialized term under the Northwest Power Act relating to the amount of electric power a Regional customer may include in its requirements purchases for the loads of the customers' industrial end-use customers. The "contracted for or committed to" loads issue involves, in effect, whether certain possible future power loads, which in aggregate would not exceed 50 annual average megawatts, will be served at Tier 1 PF Rates or at Tier 2 PF Rates. A briefing schedule has not yet been established by the court.

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. 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, among other things.

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.

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, which 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 2007 Supplemental Power Rate Record of Decision ("2007 Supplemental ROD") wherein 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 because the prior PF Preference Rates were higher than they should have been.

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 Amounts determination, power rates, the 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 Fiscal Years 2010-2011. 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, certain provisions of the final 2010-2011 power rates relating to the 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. In July 2011, Bonneville agreed to adopt the proposed settlement ("2012 Residential Exchange Program Settlement Agreement").

In October of 2011, the Association of Public Agency Customers ("APAC") (an association of end-use consumers that purchase electric power from Preference Customers) filed a petition challenging the 2012 Residential Exchange Program Settlement Agreement. On October 28, 2013, the court issued an order and opinion dismissing APAC's challenge to the 2012 Residential Exchange Program Settlement Agreement. On January 15, 2014, the court issued orders in the remaining cases challenging Bonneville's Residential Exchange Program-related decisions, removing the stay of such proceedings and seeking a statement from the petitioners and interveners as to the effect of the court's October 28, 2013 Order on the extant cases. On April 1, 2014, petitioners replied that most, but not all, petitioners believed that the outstanding litigation on the Residential Exchange Program was moot as a result of the Ninth Circuit Court's decision in APAC. To resolve the question of mootness, on May 5, 2014, parties to the settlement filed a motion to dismiss all Residential Exchange Program issues from the litigation pending before the Ninth Circuit Court. One party opposed the motion. Briefing on this issue concluded on June 27, 2014.

See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services-Residential Exchange Program."

Southern California Edison v. Bonneville Power Administration

In 2004 and 2006, Southern California Edison ("SCE") filed certain claims in the United States Court of Federal Claims against Bonneville relating to actions taken by Bonneville under a 1988 power sale contract between Bonneville and SCE.

In 2006, Bonneville and SCE executed an agreement to settle the claims, whereby Bonneville will make a settlement payment of $28.5 million plus interest to SCE in exchange for SCE's dismissing the two claims. Payment by Bonneville is due (with interest) when it receives a final resolution of its refund liability, if any, in the California refund proceedings. See "—Litigation and Related Administrative Disputes in Connection with the West Coast Power Crisis in 1999-2001."

Rates Litigation Generally

Bonneville's rates are frequently the subject of litigation in the United States Court of Appeals for the Ninth Circuit. 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 by the Court, 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.

Litigation and Related Administrative Disputes in Connection with the West Coast Power Crisis 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 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 foregoing proceedings and the problems experienced in West Coast power markets in 1999-2001 have also engendered litigation affecting Bonneville.

FERC California Refund Docket and California Breach Claims

In the "FERC California Refund Docket" FERC is examining, among other things, 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 market-clearing price auction energy markets where buyers could purchase power. Under a market-clearing auction, power sellers' bids are accepted from lowest to highest price until all power demand is met, and accepted bids are all paid the same price as the bid for the last unit of electricity needed to meet total demand (the highest price that 'clears the market'). The Cal-ISO also entered into non-market-clearing power purchases and exchanges to obtain electric power to meet loads.

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, which were obligated by law to purchase from the Cal-ISO and Cal-PX markets, later sought at FERC refunds for their purchases. In litigation arising out of the FERC 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 (the "September 2005 Ninth Circuit Court Opinion"). As a result of the court's ruling, the FERC California Refund Docket cannot in and of itself result in any FERC-ordered refund liability for Bonneville. Notwithstanding the September 2005 Ninth Circuit Court Opinion, Bonneville remains a party to the FERC California Refund Docket, as described below.

On April 25, 2012, Bonneville received $73.8 million from the Cal-ISO and Cal-PX for the principal amount of withheld outstanding payment obligations to Bonneville for sales during the period (2000-2001) at issue in the case. Under a FERC order, the accrued interest through April 25, 2012 will not become payable until the FERC California Refund Docket is finally resolved.

In light of the September 2005 Ninth Circuit Court Opinion, the California Attorney General on behalf of California Energy Scheduling Resources, which is a California state agency, and three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric, and Southern California Edison ("SCE"), (the foregoing four parties are referred to collectively herein as the "California Parties"), 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 and related transactions into the Cal-PX and Cal-ISO markets. These claims are referred to herein as the "California Breach Claims." The California Parties also seek to recover pre-judgment and post-judgment interest and litigation costs in the California Breach Claims litigation. Bonneville estimates that the aggregate refund period contract damages claimed by California Parties are approximately $41 million in specified damages (not including litigation costs and interest) plus additional unspecified amounts that could be realized through declaratory orders sought by the California Parties.

The California Parties' claims in the California Breach Claims litigation are predicated on the assertion that in its transactions into the Cal-PX and Cal-ISO markets, Bonneville had agreed by contract to accept prices by reference to tariff rates. In a May 2012 order (the "May 2012 CFC Order"), the Court of Federal Claims found that when FERC established mitigated market prices in the Cal-ISO and Cal-PX markets to calculate refunds for transacting entities that were subject to FERC's refund authority (as noted above, Bonneville was not subject to FERC's refund authority for such transactions as established in the September 2005 Ninth Circuit Court Opinion), FERC had "retroactively reset" the tariff rates in such markets. The Court of Federal Claims also found that FERC's retroactive revision of tariff rates retroactively adjusted Bonneville's contracted-for prices to an amount equal to the 'new' lower tariff rates and that Bonneville breached contracts with the California Parties by failing to pay refunds for amounts it retained in excess of the mitigated market-clearing prices. The Court of Federal Claims also found that Bonneville is liable for contract damages in the amount of the difference between the original contacted-for prices and the FERC-revised prices, as established by FERC in the FERC California Refund Docket. (As described below, the May 2012 CFC Order was set aside in December 2013 by a new judge in the California Breach Claims litigation and she has indicated she intends to dismiss the California Breach Claims.)

In September 2012, the Ninth Circuit Court, in further review of the FERC California Refund Docket, issued an opinion holding that FERC, in establishing mitigated prices in the Cal-PX and Cal-ISO markets for calculating refunds, had not retroactively reset the tariff rates in those markets (the "September 2012 Ninth Circuit Court

Opinion"). The Ninth Circuit Court found that although "FERC has authority to state retroactively what a 'just and reasonable' rate would have been pursuant to its refund authority, Congress did not provide FERC with retroactive rate setting authority over non-jurisdictional sellers" like Bonneville.

In November 2012, FERC issued a ruling in the FERC California Refund Docket determining that a remedy, if any, for power sales from May 1, 2000 through October 1, 2000 into "Day Ahead" market-clearing price power markets operated by the Cal-ISO and the Cal-PX (the "Summer 2000 Transactions") would not be made on a "market-wide" basis but rather would be based on the individual tariff violations of the sellers. Under a "market-wide" remedy, the potential amounts payable by Bonneville could be significantly higher because the price of every sale or related transaction by a seller (including, in theory, Bonneville) could be retroactively adjusted downward, irrespective of whether the seller violated the tariff in the hour at issue. The California Parties have appealed the foregoing FERC determination to the Ninth Circuit Court. The appeal has been stayed pending final resolution of a number of pending matters at FERC.

As part of the FERC California Refund Docket, an administrative law judge ("FERC ALJ") appointed by the FERC Commissioners has made certain findings related to (i) the Summer 2000 Transactions, and (ii) certain non-cleared (bi-lateral) multi-day power sales and power exchange transactions by Bonneville into the Cal-ISO's "Exchange and Multi-day" markets in 2000 and 2001 ("Exchange and Multi-day Transactions"). In February 2013, the FERC ALJ issued to the FERC Commissioners certain findings (the "February 2013 Findings"), to the effect, among other things, that Bonneville violated the tariff with 84 separate Summer 2000 Transactions. Approximately 11,000 bids were made into the Cal-ISO market during the subject period. The FERC ALJ also found that the prices charged for all of Bonneville's Exchange and Multi-day Transactions were at unjust and unreasonable rates and are subject to refund under a methodology based on the FERC ALJ's view of the value received by Bonneville under such transactions that was in excess of just and reasonable rates. The February 2013 Findings may be accepted, rejected or modified by the FERC Commissioners.

Following the issuance of the February Findings, Bonneville filed a brief with the FERC Commissioners arguing, among other things that, under the September 2005 Ninth Circuit Court Opinion and the September 2012 Ninth Circuit Court Opinion, FERC does not have authority to order refunds by non-jurisdictional utilities such as Bonneville or to modify Bonneville's rates. Bonneville also argued that the FERC ALJ's proposed refund methodology is erroneous in several respects. The California Parties have filed their response to Bonneville's brief and the parties await a ruling from the FERC Commissioners.

The FERC ALJ's proposed refund methodology could result in potential liability by Bonneville to the California Parties in the amount of approximately $108 million, including interest through February 2013, assuming, among other things, that the California Breach Claims litigation now in the Court of Federal Claims (or related litigation) concludes that Bonneville can be held liable for such potential liability and that the FERC ALJ's proposed methodology is adopted by FERC and survives litigation (if any). (As described below, a new judge in the California Breach Claims litigation has indicated she intends to dismiss the California Breach Claims.)

In certain orders issued in April 2013 (the "April 2013 CFC Orders"), the Court of Federal Claims rejected a motion by the United States Department of Justice on behalf of Bonneville and another federal power marketing administration asking the court to reconsider its May 2012 CFC Order on liability in light of the Ninth Circuit Court's September 2012 ruling that FERC had not retroactively reset tariff rates. The Court of Federal Claims ruled that the Ninth Circuit Court's opinion was not dispositive of the contract liability issue in the California Breach Claims litigation because the Ninth Circuit Court did not address how the FERC-mitigated prices affected the California Parties' breach of contract claims against Bonneville. The Court of Federal Claims also determined, in response to motions by the California Parties, that if and when FERC resets prices, Bonneville will be contractually bound to refund the value, in excess of FERC-mitigated prices, that Bonneville received from the Cal-ISO, Cal-PX, and others in the Summer 2000 Transactions and the Exchange and Multi-day Transactions (which are under review by FERC in the FERC California Refund Docket described above).

In the spring of 2013, a new Court of Federal Claims judge was assigned to the California Breach Claims case. On December 20, 2013, the new judge issued an order vacating the prior judge's substantive orders, including the April 2013 CFC Order and the May 2012 CFC Order. On February 26, 2014, the judge issued a notice to show cause why the court, on reconsideration, should not dismiss these cases, because of plaintiffs' failure to establish the requirements of standing to sue on a government contract, thereby depriving the court of jurisdiction of the case.

The judge also requested that the parties file a joint statement of the status of related proceedings at FERC and the Ninth Circuit Court since the time that the Ninth Circuit rendered the September 2012 Ninth Circuit Court Opinion (described above) concluding that FERC lacks retroactive rate setting authority over non-jurisdictional sellers like Bonneville. On June 5, 2014 the judge held the oral argument for the show cause hearing. The judge stated during the hearing she expects to issue a final order before the end of the summer 2014.

Northwest Spot Market Docket

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.

Show Cause Proceeding

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, after the effective date of the legislation, 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 1999-2001, see "—Southern California Edison v. Bonneville Power Administration."

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.

APPENDIX B-1

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Independent Auditor's Report

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

We have audited the accompanying combined financial statements of the Federal Columbia River Power System ("FCRPS"), which comprise the combined balance sheets as of September 30, 2013 and 2012, and the related combined statements of revenues and expenses and of cash flows for each of the three years in the period ended September 30, 2013.

Management's Responsibility for the Combined Financial Statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the combined financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the combined financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the FCRPS' preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the FCRPS' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

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Opinion

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the financial position of the Federal Columbia River Power System at September 30, 2013 and 2012, and the results of its operations and its cash flows for the three years in the period ended September 30, 2013 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 30, 2013

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

(Thousands of Dollars)

	2013	2012
Assets		
Utility plant		
Completed plant	**$ 16,153,536**	$ 15,401,287
Accumulated depreciation	**(5,700,821)**	(5,449,470)
	10,452,715	9,951,817
Construction work in progress	**1,344,033**	1,412,134
Net utility plant	**11,796,748**	11,363,951
Nonfederal generation	**3,243,713**	3,318,494
Current assets		
Cash and cash equivalents	**1,010,128**	948,859
Short-term investments in U.S. Treasury securities	**388,914**	242,495
Accounts receivable, net of allowance	**29,540**	86,632
Accrued unbilled revenues	**260,757**	248,769
Materials and supplies, at average cost	**112,019**	99,436
Prepaid expenses	**40,458**	26,060
Total current assets	**1,841,816**	1,652,251
Other assets		
Regulatory assets	**6,953,397**	7,464,988
Investments in U.S. Treasury securities	**34,961**	49,623
Nonfederal nuclear decommissioning trusts	**254,752**	235,598
Deferred charges and other	**146,682**	180,444
Total other assets	**7,389,792**	7,930,653
Total assets	**$ 24,272,069**	$ 24,265,349

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)

	2013	2012
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,432,217**	$ 2,595,940
Federal appropriations	**4,291,457**	4,249,022
Borrowings from U.S. Treasury	**3,738,040**	3,263,040
Nonfederal debt	**6,229,004**	6,370,733
Total capitalization and long-term liabilities	**16,690,718**	16,478,735
Commitments and contingencies (Note 14)		
Current liabilities		
Borrowings from U.S. Treasury	**147,000**	157,800
Nonfederal debt	**607,865**	493,650
Accounts payable and other	**503,112**	554,006
Total current liabilities	**1,257,977**	1,205,456
Other liabilities		
Regulatory liabilities	**2,434,065**	2,545,370
IOU exchange benefits	**2,992,740**	3,081,053
Asset retirement obligations	**171,554**	161,215
Deferred credits and other	**725,015**	793,520
Total other liabilities	**6,323,374**	6,581,158
Total capitalization and liabilities	**$ 24,272,069**	$ 24,265,349

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)

	2013	2012	2011
Operating revenues			
Sales	**$ 3,175,570**	$ 3,179,592	$ 3,134,209
U.S. Treasury credits for fish	**84,092**	76,983	85,102
Miscellaneous revenues	**86,619**	61,275	65,463
Total operating revenues	**3,346,281**	3,317,850	3,284,774
Operating expenses			
Operations and maintenance	**1,843,972**	1,796,902	1,734,306
Purchased power	**154,173**	143,119	177,953
Nonfederal projects	**733,313**	659,680	624,972
Depreciation and amortization	**429,717**	389,097	393,502
Total operating expenses	**3,161,175**	2,988,798	2,930,733
Net operating revenues	**185,106**	329,052	354,041
Interest expense and (income)			
Interest expense	**356,337**	331,732	352,904
Allowance for funds used during construction	**(37,529)**	(45,845)	(42,983)
Interest income	**(28,937)**	(43,587)	(37,562)
Net interest expense	**289,871**	242,300	272,359
Net (expenses) revenues	**(104,765)**	86,752	81,682
Accumulated net revenues at October 1	**2,595,940**	2,510,373	2,428,691
Irrigation assistance	**(58,958)**	(1,185)	-
Accumulated net revenues at September 30	**$ 2,432,217**	$ 2,595,940	$ 2,510,373

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)

	2013	2012	2011
Cash flows from operating activities			
Net (expenses) revenues	$ (104,765)	$ 86,752	$ 81,682
Non-cash items:			
Depreciation and amortization	429,717	389,097	393,502
Amortization of nonfederal projects	512,363	390,266	306,175
Changes in:			
Receivables and unbilled revenues	45,261	(7,564)	(5,112)
Materials and supplies	(12,583)	(5,512)	(8,127)
Prepaid expenses	(14,398)	3,370	(3,598)
Accounts payable and other	(53,511)	35,084	(50,229)
Regulatory assets and liabilities	(141,867)	(162,772)	(209,173)
Other assets and liabilities	(91,572)	(80,698)	(68,134)
Net cash provided by operating activities	568,645	648,023	436,986
Cash flows from investing activities			
Investment in utility plant, including AFUDC	(778,785)	(861,754)	(787,384)
U.S. Treasury securities:			
Purchases	(940,000)	(635,000)	(310,000)
Maturities	808,783	638,767	163,193
Deposits to nonfederal nuclear decommissioning trusts	(3,598)	(9,211)	(9,616)
Lease financing trust funds:			
Deposits to	(144,208)	(202,287)	(106,260)
Receipts from	160,095	231,994	66,601
Net cash used for investing activities	(897,713)	(837,491)	(983,466)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	99,175	104,696	129,632
Repayment	(56,740)	(164,594)	(39,528)
Borrowings from U.S. Treasury:			
Proceeds	632,000	806,000	800,000
Repayment	(167,800)	(328,600)	(370,000)
Nonfederal debt:			
Proceeds	488,965	202,289	201,963
Extinguished through refinancing	-	-	(90,000)
Repayment	(498,748)	(364,388)	(308,277)
Customers:			
Net advances (refunds) for construction	(6,425)	27,634	59,806
Repayment of funds used for construction	(41,132)	(35,650)	(23,662)
Irrigation assistance	(58,958)	(1,185)	-
Net cash provided by financing activities	390,337	246,202	359,934
Net increase (decrease) in cash and cash equivalents	61,269	56,734	(186,546)
Cash and cash equivalents at beginning of year	948,859	892,125	1,078,671
Cash and cash equivalents at end of year	$ 1,010,128	$ 948,859	$ 892,125
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	$ 377,167	$ 350,581	$ 375,755
Significant noncash investing and financing activities:			
Federal appropriations	$ -	$ (40,583)	$ -
Nonfederal debt increase for Energy Northwest	$ 12,639	$ 782,655	$ 147,145
Debt actions by Energy Northwest	$ (20,235)	$ (66,865)	$ -
Other nonfederal	$ (10,135)	$ 38,101	$ -

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 operations 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. 839e(a)(2), and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. Statutory standards include a requirement that rates must 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 the final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court) if challenged by parties involved in the rate proceedings. Petitions seeking such review must be filed within 90 days of the final FERC approval. 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. 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 $8.43 billion and $8.17 billion at Sept. 30, 2013, and 2012, respectively. Transmission assets were $7.72 billion and $7.23 billion, including assets under capital lease agreements of $127.7 million and $127.6 million, at Sept. 30, 2013, and 2012, respectively. The costs of substantial additions, major replacements and substantial betterments are capitalized. Costs include 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 48 years. The estimated net cost of removal is included in depreciation. In the event removal costs are expected to exceed salvage proceeds, a reclassification of this negative salvage is made from accumulated depreciation to a regulatory liability. As actual removal costs are incurred, the associated regulatory liability is reduced. (See Note 3, Effects of Regulation.)

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 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 for appropriated and BPA funds were approximately 0.1 percent and 3.6 percent in fiscal year 2013, 0.1 percent and 4.1 percent in fiscal year 2012, and 0.3 percent and 4.4 percent in fiscal year 2011. The weighted-average AFUDC rates for fiscal years 2013, 2012 and 2011 approximated the BPA rates for these years.

Nonfederal generation

BPA contracted to acquire all of the generating capability of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant and Lewis County PUD's Cowlitz Falls Hydroelectric Project. The contracts to acquire the generating capability of the facilities require BPA to pay all of the facilities' 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 consist of short-term U.S. Treasury market-based special securities with maturities of 90 days or less at the date of investment. 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 customers throughout the western United States and Canada, which include consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators and others. BPA's accounts receivable exposure is generally from large and stable counterparties and does not represent a significant concentration of credit risk. During fiscal years 2013, 2012 and 2011, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings.

BPA mitigates credit risk 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, and cash in the form of prepayments, deposits or escrow funds 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 balance is not material to the financial statements.

Derivative instruments

BPA measures its derivative instruments at fair value and recognizes them on the Combined Balance Sheets as either an asset or liability unless the contract is eligible for the normal purchases and normal sales exception 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 derivative accounting definition of capacity. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

The fair value of derivative instruments that do not qualify for the normal purchases and normal sales exception are recognized on the Combined Balance Sheets as deferred credits or deferred charges. Changes in fair value are not recognized in the Combined Statements of Revenues and Expenses but are deferred as either regulatory assets or regulatory liabilities in accordance with Regulated Operations accounting guidance.

Fair value

BPA's carrying amounts of current assets and current liabilities approximate fair value based on the short-term nature of these instruments. In accordance with authoritative guidance for Fair Value Measurements, 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 12, Risk Management and Derivative Instruments and Note 13, Fair Value Measurements.)

Revenues and net revenues

Operating revenues are recorded when power, transmission and related services are delivered and include estimated unbilled revenues. BPA's net revenues over time are committed to payment of operational obligations, including debt for both operating and nonoperating nonfederal projects, repayment of the U.S. government investment in the FCRPS, and the payment of certain irrigation costs.

Interest income

Interest income includes earnings on BPA's fund balance with the U.S. Treasury, on investments in market-based special securities and from other sources. BPA earns interest credits on cash balances in the fund not invested in market-based specials at the weighted-average interest rate of its outstanding U.S. Treasury borrowings and reduces some of its monthly debt interest payments by the interest earned. Interest earnings on U.S. Treasury market-based special investments are based on the stated rates of the individual securities.

U.S. Treasury credits for fish

Under the Northwest Power Act, BPA makes expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes on a reimbursement basis. Section 4(h)10(c) of the Northwest Power Act also specifies that consumers of electric power, through rates BPA establishes 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." This provision of law ensures that the costs of mitigating these impacts are properly accounted for among the power-related and other purposes of the hydroelectric projects of the FCRPS. Power-related costs are recovered in BPA's rates. Nonpower-related costs are recovered as a reduction to BPA's cash payments to the U.S. Treasury and are shown as a component of Operating revenues in the Combined Statements of Revenues and Expenses.

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. Program costs are 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, and 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 the expense in the year it is applied. (See Note 10, Residential Exchange Program.)

Pension and Other Postretirement Benefits

Federal employees associated with the operation of the FCRPS participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate in the Federal Employees Health and Benefit Program and the Federal Employee Group Life Insurance Program. All such postretirement systems and programs are sponsored by the Office of Personnel Management; therefore, BPA does not record any accumulated plan assets or liabilities related to the administration of such programs. Contribution amounts are included in rates and are recorded as expense during the year to which the payment relates.

RECENT ACCOUNTING PRONOUNCEMENTS

Balance Sheet Offsetting

In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance that requires an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance will be effective for fiscal year 2014. BPA is evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

Fair value measurements and disclosures

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 relevance to BPA include certain additional required disclosures for Level 2 and 3 fair value measurements. BPA adopted this guidance on October 1, 2012. This guidance had no impact to BPA's financial condition, results of operations or cash flows.

SUBSEQUENT EVENTS

FCRPS has performed an evaluation of events and transactions for potential recognition or disclosure through Oct. 30, 2013, which is the date the financial statements were issued.

2. Investments in U.S. Treasury Securities

As of Sept. 30 — thousands of dollars	**2013**		2012	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Short-term	**$ 388,914**	**$ 389,127**	$ 242,495	$ 242,911
Long-term	**34,961**	**34,972**	49,623	49,984
Total	**$ 423,875**	**$ 424,099**	$ 292,118	$ 292,895

BPA participates in the U.S. Treasury's Federal Investment Program which provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and have statutory 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 at least $100 million annually for up to 10 years or until the BPA fund is fully invested. Any remaining balance in the BPA fund at Sept. 30, 2018, will be invested through the Federal Investment Program.

Market-based specials held during fiscal years 2013 and 2012 had a weighted-average yield of 0.3 percent and 0.4 percent, respectively, and maturities of up to two years. The amounts shown in the preceding table 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 at October 2015.

3. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars	**2013**	2012
REP Scheduled Amounts	**$ 2,903,634**	$ 2,993,310
Terminated nuclear facilities	**2,154,900**	2,606,661
Columbia River Fish Mitigation	**600,413**	546,604
REP Refund Amounts	**432,850**	500,155
Conservation measures	**319,082**	297,838
Fish and wildlife measures	**302,245**	278,102
Legal claims and settlements	**76,601**	74,419
Spacer damper replacement program	**46,563**	37,775
Federal Employees' Compensation Act	**32,558**	31,352
Derivative instruments	**27,108**	39,049
Trojan decommissioning and site restoration	**24,431**	23,189
Terminated hydro facilities	**17,238**	18,602
Capital bond premiums	**9,067**	9,810
Other	**6,707**	8,122
Total	**$ 6,953,397**	$ 7,464,988

Regulatory assets include the following items:

"REP Scheduled Amounts" reflect the costs of REP Scheduled Amounts representing REP benefits payable under the 2012 REP Settlement Agreement that will be recovered through rates through 2028. (See Note 10, Residential Exchange Program.)

"Terminated nuclear facilities" consists of 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.)

"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.

"REP Refund Amounts" is the amount recoverable in future rate periods that reduces the REP benefit payments through 2019 as set forth in the 2012 REP Settlement Agreement. (See Note 10, Residential Exchange Program.)

"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.

"Legal claims and settlements" reflect accrued liabilities related to outstanding legal claims and settlement agreements. These costs will be recovered and amortized through future rates over a period as established by the administrator.

"Spacer damper replacement program" consists of costs to replace deteriorated spacer dampers and are being recovered in rates under the Spacer Damper Replacement Program. These costs are being amortized over a period of 25 or 30 years. In fiscal year 2011, BPA recognized an impairment charge of $20.6 million in deferred spacer damper replacement program costs.

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

"Derivative instruments" reflect the unrealized losses from BPA's derivative portfolio. (See Note 12, 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.)

"Terminated hydro facilities" consists of the nonfederal debt for the terminated Northern Wasco hydro project. These assets are amortized over the term of the related outstanding debt. (See Note 8, Nonfederal Financing.)

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

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars	**2013**	2012
Capitalization adjustment	**$ 1,471,986**	$ 1,536,891
REP Refund Amounts to COUs	**432,850**	500,155
Accumulated plant removal costs	**408,218**	390,622
CGS decommissioning and site restoration	**109,819**	99,182
Other	**11,192**	18,520
Total	**$ 2,434,065**	$ 2,545,370

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 2013, 2012 and 2011, respectively. (See Note 6, Federal Appropriations.)

"REP Refund Amounts to COUs" is the amount previously collected through rates that is owed to qualifying consumer-owned utilities and will be credits on their future bills. These costs will be repaid and amortized through future rates over the period as established in the 2012 REP Settlement Agreement, and are equal to regulatory assets for REP refund amounts. (See Note 10, Residential Exchange Program.)

"Accumulated plant removal costs" are the amounts previously collected through rates as part of depreciation. The liability will be relieved as actual removal costs are incurred. In fiscal year 2012, collections associated with estimated removal costs in prior years of $178.8 million were reclassified from accumulated depreciation to this regulatory liability. This adjustment was not considered material to previously issued financial statements.

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

4. Asset Retirement Obligations

As of Sept. 30 — thousands of dollars	**2013**	2012
Beginning Balance	**$ 161,215**	$ 176,212
Activities:		
Accretion	**8,507**	8,305
Expenditures	**(596)**	(1,269)
Revisions	**2,428**	(22,033)
Ending Balance	**$ 171,554**	$ 161,215

BPA recognizes AROs based on 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. During fiscal year 2012, the ARO for CGS decreased by $15.0 million primarily due to a revised cost estimate following Nuclear Regulatory Commission (NRC) relicensing of the facility for an additional 20 years. FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO since no future obligation exists to remove these assets.

AROs include the following items as of Sept. 30, 2013:

- CGS decommissioning and site restoration of $126.5 million;
- Trojan decommissioning of $24.4 million;
- Energy Northwest Project Nos. 1 and 4 site restoration of $20.6 million.

Decommissioning costs for CGS are charged to operations over the operating life of the project.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — thousands of dollars	**2013**		2012	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Equity index funds	**$ 87,723**	**$ 117,212**	$ 84,377	$ 100,050
U.S. government obligation mutual funds	**77,022**	**76,801**	72,200	74,067
Corporate bond index funds	**59,402**	**60,726**	57,150	61,460
Cash and cash equivalents	**13**	**13**	21	21
Total	**$ 224,160**	**$ 254,752**	$ 213,748	$ 235,598

BPA recognizes an asset that represents trust fund balances for decommissioning and site restoration costs. 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 NRC requirements. The NRC requires that this period be no longer than 60 years from the time the plant stops operating. In May 2012, the NRC renewed CGS's operating license for an additional 20 years and the license now expires in 2043. 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 accounts are classified by BPA as available-for-sale in accordance with accounting guidance related to Investments, Debt and Equity Securities.

BPA recognizes the unrealized gains and losses on these investment securities as adjustments to the related regulatory liability, which represents the excess of the amount previously collected through rates over the current ARO balance. (See Note 3, Effects of Regulation.) Payments to the trusts for fiscal years 2013, 2012 and 2011 were approximately $3.6 million, $9.2 million and $9.6 million, respectively. In connection with the relicensing of CGS in 2012, funding of the trust was reassessed and resulted in a reduction in annual contributions beginning in fiscal year 2013.

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	**2013**	2012
Lease financing trust funds	**$ 99,623**	$ 121,032
Settlements receivable	**16,000**	16,000
Spectrum Relocation fund	**8,307**	9,608
Funding agreements	**7,174**	7,174
Derivative instruments	**4,814**	12,141
Energy receivable	**4,391**	4,768
Trust fund and other deposits	**3,103**	6,290
Other	**3,270**	3,431
Total	**$ 146,682**	$ 180,444

Deferred charges and other include the following items:

"Lease financing 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.)

"Settlements receivable" represents interest earned by BPA on certain settlements, the principal of which has been collected. The timing of cash receipt of the interest is unknown.

"Spectrum Relocation fund" was created 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 Commercial Spectrum Enhancement Act are held in the BPA fund and are restricted for use in constructing replacement assets.

"Funding agreements" represents deferred costs associated with BPA's contractual obligations to determine the feasibility of certain joint transmission projects.

"Derivative instruments" represent unrealized gains from the derivative portfolio which includes physical power purchase and sale transactions and power exchange transactions.

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

"Trust fund and other deposits" primarily represent funds held in the Conservation and Renewable Energy System (CARES) defeasance trust fund.

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 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. All outstanding federal appropriations are due 2019 and thereafter.

The weighted-average interest rate was 6.1 percent and 6.2 percent on outstanding appropriations as of Sept. 30, 2013, and 2012, respectively.

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 bonds or related debt instruments 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.

As of Sept. 30, 2013, of the total $3.89 billion of outstanding bonds, none related to NW Power Act expenses and $361.0 million were for conservation and renewable resources investments. Outstanding bonds carrying a variable rate of interest were $300.0 million at both Sept. 30, 2013, and 2012. 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 $297.2 million and $484.8 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2013, and 2012, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 3.8 percent and 3.6 percent as of Sept. 30, 2013, and 2012, respectively. As of Sept. 30, 2013, the outstanding bonds with a variable rate of interest carried an interest rate of 0.1 percent.

Of the outstanding U.S. Treasury borrowings, $278.8 million is not subject to redemption prior to their stated maturities. As of Sept. 30, 2013, $512.0 million are callable by BPA at par value and the remaining $3.10 billion are callable by BPA 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	
2014	$ 147,000
2015	210,000
2016	30,000
2017	68,400
2018	9,000
2019 through 2043	3,420,640
Total	**$ 3,885,040**

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars	**2013**	2012
Nonfederal generation:		
Columbia Generating Station	**$ 3,175,659**	$ 3,224,040
Cowlitz Falls	**87,995**	104,650
Nonfederal generation	**3,263,654**	3,328,690
Terminated generation:		
Nuclear Project No. 1	**1,048,005**	1,321,060
Nuclear Project No. 3	**1,229,245**	1,395,405
Terminated nuclear facilities	**2,277,250**	2,716,465
Terminated Northern Wasco Hydro Project	**18,375**	19,735
Sponsored conservation:		
Tacoma	**3,495**	5,120
Conservation and Renewable Energy System	**3,004**	5,870
Sponsored conservation	**6,499**	10,990
Lease financing program	**713,762**	668,054
Customer prepaid power purchases	**334,909**	-
Capital leases	**222,420**	120,449
Total	**$ 6,836,869**	$ 6,864,383

Nonfederal generation, terminated generation and sponsored conservation

BPA contracted to acquire all of the generating capability of Energy Northwest's Columbia Generating Station and Lewis County PUD's Cowlitz Falls Hydroelectric Project. These contracts require that BPA pay all of the operating, maintenance and debt service costs for these projects. BPA also contracted to acquire all of the generating capacity of Energy Northwest's Nuclear Project No. 1 and 70 percent of Energy Northwest's Nuclear Project No. 3; however, these projects were terminated prior to completion. Although not in operation, BPA is required by these contracts to pay debt service costs for these projects.

BPA funds debt service on Conservation and Renewable Energy System (CARES) and City of Tacoma Conservation bonds issued to finance conservation programs sponsored by BPA. BPA is also required by The Settlement and Termination Agreement between BPA and the Northern Wasco PUD to pay annual debt service on the terminated Northern Wasco Hydro Project.

BPA recognizes expenses for these nonfederal projects based on total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $307.3 million, $298.3 million and $328.1 million in fiscal years 2013, 2012 and 2011, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $733.3 million, $659.7 million and $625.0 million for fiscal years 2013, 2012 and 2011, respectively, is reported as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

On the accompanying Combined Balance Sheets, related assets for operating projects are included in Nonfederal generation. Related assets for terminated generation and sponsored conservation are included in Regulatory assets. (See Note 3, Effects of Regulation.)

The underlying debt for the Energy Northwest obligations (including terminated nuclear facilities Projects Nos. 1 and 3 and CGS) currently matures through 2044 with interest rates that are fixed between 1.1 percent and 7.1 percent. Energy Northwest debt of $1.61 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2014 and July 2024 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded recorded value by $510.7 million and $824.2 million as of Sept. 30, 2013, and 2012, 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 4.6 percent for the Energy Northwest outstanding nonfederal debt at both Sept. 30, 2013, and 2012, respectively.

Lease financing program

Under the Lease Financing Program, BPA consolidates six 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 $593.4 million on lines of credit with various banks as of Sept. 30, 2013. The bonds bear interest at 5.4 percent and mature in 2034. All NIFC bonds outstanding are subject to redemption by the issuing 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 Jan. 1, 2015, and Jan. 1, 2019.

On the accompanying Combined Balance Sheets, the bonds and bank line of credit facilities are included in Nonfederal debt. The leased assets are primarily included in Utility plant and also in Deferred charges and other for unspent funds held in trust.

In July 2012, NIFC II sold its lease receivable, rights to future lease revenue, and title to the leased assets to the Port of Morrow, a port district located in Morrow County, Oregon. As the Port of Morrow is not consolidated in the combined FCRPS financial statements, the lease is reported as a capital lease included in Nonfederal debt. The net effect of this transaction was a decrease in Nonfederal debt of $12.4 million and a gain of $1.9 million.

The fair value of the combined NIFC bonds and lines of credit exceeded the recorded value by $30.2 million and $45.5 million as of Sept. 30, 2013, and 2012, respectively. The valuations are based on the discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2013, and 2012, respectively. The weighted-average interest rate on the NIFCs' outstanding debt was 3.5 percent and 3.6 percent as of Sept. 30, 2013, and 2012, respectively.

Customer prepaid power purchases

During fiscal year 2013 BPA entered into agreements with four regional COUs for the express advance payment of customer power purchases. Under this program, customers purchased prepaid power in blocks through fiscal year 2028. For each block purchased BPA provides monthly fixed credits on the customers' power bills.

In March 2013, BPA received $340.0 million representing $474.3 million in scheduled credits for blocks purchased by customers. BPA accounts for the prepayment proceeds as a financing transaction and reports the value of the obligations associated with the fixed credits as a prepayment liability. Interest expense is recognized using a weighted-average effective interest rate of 4.5 percent. The prepaid liability is reduced as power is delivered and the credits are applied.

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

2014	$	606,644
2015		799,965
2016		817,999
2017		593,456
2018		931,617
2019 and thereafter		2,864,768
Total	**$**	**6,614,449**

Capital leases

Capital leases include BPA's lease agreements with the Port of Morrow and other counterparties for transmission facilities and equipment, including lines, substations and general plant assets. Completed plant assets under capital lease agreements were $127.7 million and $127.6 million, and the accumulated depreciation was $19.3 million and $16.1 million, at Sept. 30, 2013, and 2012, respectively. The capital leases expire on various dates through 2044. Generally, the capital lease agreements contain provisions that allow BPA to purchase the leased assets at anytime during each lease term for a bargain purchase price plus the value of the related outstanding debt instrument. Additionally, one lease agreement includes a minimum lease payment escalation clause based on transmission usage.

FUTURE MINIMUM LEASE PAYMENTS UNDER CAPITAL LEASES

As of Sept. 30 — thousands of dollars	
2014	$ 9,621
2015	9,613
2016	9,615
2017	9,617
2018	9,619
2019 and thereafter	315,072
Total undiscounted payments	$ 363,157
Less: Executory costs	32,407
Less: Amount representing interest	108,330
Present value of minimum lease payments	**222,420**
Less: Current portion	1,221
Long-term capital lease liability	$ 221,199

9. Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional financial support or whose equity investors lack characteristics of a controlling financial interest. An enterprise that has a controlling interest is known as the VIE's primary beneficiary and is required to consolidate the VIE.

BPA reviews executed power purchase agreements with counterparties that may be considered VIEs. These VIEs are typically legal entities structured to own and operate specific generating facilities, primarily wind farms. Because of their pricing arrangements, these agreements may 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 it does not control the operating and maintenance activities that most significantly impact these entities. Therefore, BPA is not considered the primary beneficiary of these VIEs and does not consolidate any entities because of power purchase agreements.

BPA is the primary beneficiary of the NIFCs, which are considered VIEs, and BPA therefore consolidates these entities into the FCRPS financial statements. 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 is responsible for constructing the leased facilities. BPA also has exclusive use and control of the facilities during the lease periods and has indemnified the equity owners for all construction and operating risks associated with the transmission facilities. At any time during each lease term, BPA has the option to buy the transmission facilities at a bargain purchase price plus the value of the related outstanding debt instruments. BPA is obligated to indemnify certain expenses of the NIFCs related to their respective facilities.

Amounts related to the NIFC entities include Deferred charges and other assets of $27.0 million and $32.3 million and Nonfederal debt of $713.0 million and $668.1 million as of Sept. 30, 2013, and 2012, respectively. In July 2012, NIFC II recorded a gain of $1.9 million on the sale of a lease.

10. 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.

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). This rate case established Lookback Amounts (representing amounts over-collected from COUs in prior years' rates, which also represented the amounts overpaid to the IOUs in the prior year's settlement agreements) that were also confirmed in the subsequent 2010 Wholesale Power and Transmission Rate Adjustment Proceeding. 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.

2008 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 Record of Decision (ROD), if any, are resolved. (See Note 14, 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 them for their 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 2013, this balance has increased to $89.1 million and is reported as part of the IOU exchange benefits liability of $2.99 billion as of Sept. 30, 2013.

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 (2012 Settlement Agreement). In March 2011, BPA distributed the 2012 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 2012 Settlement Agreement and determine whether it was in the region's best interest for the BPA administrator to sign the Settlement Agreement on behalf of BPA. In July 2011, the BPA administrator signed the REP-12 Final ROD and the 2012 Settlement Agreement.

In 2011, BPA recorded a long-term IOU exchange benefits liability and corresponding regulatory asset of $3.07 billion associated with the Settlement Agreement. Beginning in fiscal year 2012, under the provisions of the 2012 Settlement Agreement the IOUs began to receive Scheduled Amounts annually 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 is established in the 2012 Settlement Agreement that relies upon IOU's average system cost, BPA's Priority Firm Exchange rates and exchange load. The settled Scheduled Amounts to be paid to the IOUs total $4.07 billion over the 17-year period through 2028. Amounts recorded of $2.90 billion at Sept. 30, 2013, represent the present value of future cash outflows for these exchange benefits.

In addition to Scheduled Amounts, the 2012 Settlement Agreement calls for Refund Amounts to be paid to COUs in the amount of $76.5 million each year from 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 2012 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 as a regulatory liability of $432.8 million at Sept. 30, 2013, represent the present value of future cash flows for the amounts to be refunded to COUs, as well as reduced exchange benefits. The distribution of the Refund Amounts will be split 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 Case and 50 percent 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 (BP-12 Rate Case).

11. Deferred Credits and Other

As of Sept. 30 — thousands of dollars	**2013**	2012
Customer reimbursable projects	**$ 227,120**	$ 232,516
Generation interconnection agreements	**219,510**	271,714
Third AC Intertie capacity agreements	**104,406**	99,231
Legal claims and settlements	**82,580**	80,904
Federal Employees' Compensation Act	**32,558**	31,352
Derivative instruments	**27,108**	39,049
Fiber optic leasing fees	**27,004**	32,599
Other	**4,729**	6,155
Total	**$ 725,015**	$ 793,520

Deferred credits and other include the following items:

"Customer reimbursable projects" consist of advances received from customers where either the customer or BPA will own the resulting asset. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, the revenue is recognized over the life of the asset once the corresponding asset is placed in service.

"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 cash or credits against future transmission service on the new or upgraded lines.

"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.

“Legal claims and settlements” reflect amounts accrued for outstanding legal claims and settlements. (See Note 14, Commitments and Contingencies.)

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

“Derivative instruments” reflect the unrealized loss of the derivative portfolio which includes physical power purchase and sale transactions.

“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 through 2024.

12. 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 13, 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 electricity 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

BPA has exposure to commodity price risk through fluctuations in electricity market prices that affect the value of energy bought and sold. Volumetric risk is the uncertainty of energy production from the hydro system. The combination of the two results in net revenue uncertainty. BPA routinely models commodity price risk and volumetric risk through parametric calculations, Monte Carlo simulations and general market observations to derive net revenues at risk, mark-to-market valuations, value at risk and other metrics as appropriate. These metrics capture the uncertainty around single point forecasts in order to monitor changes in the revenue risk profile from changes in market price, market price volatility and forecasted hydro generation. BPA measures and monitors the output of these methods on a regular basis. In order to mitigate revenue uncertainty that is beyond the agency’s risk tolerance, BPA enters into short-term and long-term purchase and sale contracts by using instruments such as forwards, futures, swaps, and options.

CREDIT RISK

Credit risk relates to the loss that might occur as a result of counterparty non-performance. BPA mitigates credit risk 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. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. BPA uses scoring models, publicly available financial information and external ratings from major credit rating agencies to determine appropriate levels of credit for its counterparties.

During fiscal year 2013, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2013, BPA had $25.9 million in credit exposure to purchase and sale contracts after 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 $21.0 million, or 81.0 percent, of the total credit exposure.

INTEREST RATE RISK

BPA has the ability to issue variable rate debt to the U.S. Treasury. BPA manages the interest rate risk presented by variable rate U.S. Treasury debt by holding an identical amount of variable rate U.S. Treasury security investments with a similar maturity profile. These U.S. Treasury investments earn interest at a variable rate that is correlated, but not identical, to the interest rate paid on U.S. Treasury variable rate debt. (See Note 2, Investments in U.S. Treasury Securities and Note 7, Borrowings from U.S. Treasury.)

DERIVATIVE INSTRUMENTS

Commodity Contracts

BPA's forward electricity contracts are eligible for the normal purchases and normal sales exception if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the derivative accounting definition of capacity described in the Derivatives and Hedging accounting guidance. These transactions are not 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.

For derivative instruments not eligible for the normal purchases and normal sales exception, BPA recorded unrealized gains of $4.6 million and unrealized losses of $30.4 million in Regulatory assets and liabilities in the Combined Balance Sheets in fiscal years 2013 and 2012, respectively. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses as the contracts are delivered and settled.

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 13, Fair Value Measurements.)

As of Sept. 30, 2013, the derivative commodity contracts recorded at fair value totaled 4.8 million MWh (gross basis) with delivery months extending to September 2019. BPA does not apply hedge accounting.

DERIVATIVE ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

As of Sept. 30 — thousands of dollars	**2013**	2012
Assets		
Derivative instruments [1]		
Commodity contracts, gross	**$ 5,377**	$ 14,263
Less: netting [2]	**(563)**	(2,122)
Total, net	**$ 4,814**	$ 12,141
Liabilities		
Derivative instruments [1]		
Commodity contracts, gross	**$ (27,671)**	$ (41,171)
Less: netting [2]	**563**	2,122
Total, net	**$ (27,108)**	$ (39,049)

[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 11, Deferred Credits and Other.)
[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

13. Fair Value Measurements

BPA applies Fair Value Measurements and Disclosures accounting guidance to certain assets and liabilities including commodity derivative instruments, nuclear decommissioning trusts and other investments. 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 investments, 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 commodity derivatives and certain agency securities as part of the lease financing trust funds investments. Fair value for certain non-exchange traded derivatives is based on forward exchange market prices and broker quotes adjusted and discounted. Lease financing trust funds investments are based on a market input evaluation pricing methodology using a combination of observable market data such as current market trade data, reported bid/ask spreads, and institutional bid information.

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 where inputs into the valuation are indicative broker quotes for a significant tenor.

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.

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, 2013, and 2012.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2013 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
Equity index funds	$117,212	$ —	$ —	$ —	**$ 117,212**
U.S. government obligation mutual funds	76,801	—	—	—	**76,801**
Corporate bond index funds	60,726	—	—	—	**60,726**
Cash and cash equivalents	13	—	—	—	**13**
Derivative instruments [1]					
Commodity contracts	—	630	4,747	(563)	**4,814**
Lease financing trust funds					
U.S. government sponsored enterprise obligations	—	50,265	—	—	**50,265**
U.S. government obligations	—	21,676	—	—	**21,676**
Total	$254,752	$ 72,571	$ 4,747	$ (563)	**$ 331,507**
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(27,671)	$ —	$ 563	**$ (27,108)**
Total	$ —	$(27,671)	$ —	$ 563	**$ (27,108)**

As of Sept. 30, 2012 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
Equity index funds	$100,050	$ —	$ —	$ —	$ 100,050
U.S. government obligation mutual funds	74,067	—	—	—	74,067
Corporate bond index funds	61,460	—	—	—	61,460
Cash and cash equivalents	21	—	—	—	21
Derivative instruments [1]					
Commodity contracts	—	258	14,005	(2,122)	12,141
Lease financing trust funds					
U.S. government sponsored enterprise obligations	—	73,117	—	—	73,117
U.S. government obligations	—	17,979	—	—	17,979
Total	$235,598	$ 91,354	$ 14,005	$ (2,122)	$ 338,835
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(41,132)	$ (39)	$ 2,122	$ (39,049)
Total	$ —	$(41,132)	$ (39)	$ 2,122	$ (39,049)

[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 11, Deferred Credits and Other.) See Note 12, Risk Management and Derivative Instruments for more information related to BPA's risk management strategy and use of derivative instruments.

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

Level 3 derivative commodity contracts are power contracts measured at fair value on a recurring basis using the California-Oregon Border (COB) forward price curve. COB does not have a sufficient number of transactions to be considered a liquid trading point. Therefore, COB prices are considered unobservable. Prices are considered a key component to COB contract valuations. All valuation pricing data is generated internally by BPA's risk management organization.

The risk management organization constructs the COB forward price curve through the use of broker quotes and bid/offer spreads to a more liquid trading point. In periods where broker quotes are not available, the risk management organization derives monthly prices by applying seasonal shaping factors and/or models monthly prices based on historical broker quotes and spreads from a closely located major trading point. BPA management believes this approach maximizes the use of pricing information from external sources and is currently the best option for valuation.

The fair value of derivative commodity contracts transacted at COB was $4.7 million at Sept. 30, 2013. The volumes under these contracts will be physically delivered in various quantities through April 2016.

As of Sept. 30, 2013, forward prices for power to be delivered at COB through April 2016 varied as shown in the following table. All prices are presented in dollars per megawatt-hour.

COB	Low	High	Weighted Average
On-Peak	$32.30	$49.36	$42.37
Off-Peak	$21.77	$43.47	$34.28

Forward power prices are influenced by, among other factors, seasonality, hydro forecasts, expectations of demand growth, planned changes in the regional generating plants, and the emergence of new marginal fuels for generation.

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.

As of Sept. 30 — thousands of dollars	**2013**	2012
Beginning Balance	**$ 13,966**	$ 24,643
Changes in unrealized gains (losses)[1]	**(9,219)**	(10,677)
Ending Balance	**$ 4,747**	$ 13,966

[1] Unrealized gains and losses are included in Regulatory assets and liabilities in the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses.

14. 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 $799.7 million as of Sept. 30, 2013. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — thousands of dollars		
2014	$	52,547
2015		52,108
2016		60,954
2017		51,391
2018		27,564
2019 through 2045		362,322
Total	**$**	**606,886**

As directed by law, BPA is required to establish rates sufficient 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 when paid. Future irrigation assistance payments are scheduled to total $606.9 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 repay these costs.

FIRM PURCHASE POWER COMMITMENTS

As of Sept. 30 — thousands of dollars		
2014	$	40,190
2015		24,656
2016		22,058
2017		26,582
2018		31,036
2019		33,699
Total	**$**	**178,221**

BPA periodically enters into long-term commitments to purchase power for future delivery. 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 including entering into power purchase commitments. Additionally, under BPA's current tiered rates structure, BPA's customers may request that BPA meet their power requirements in excess of their share of BPA's generation resources. BPA may meet these requests by entering into power purchase commitments. The above table includes firm purchase power agreements of known costs that are currently in place to assist in meeting expected future obligations under long-term power sales contracts. Included are five contracts for winter purchases through fiscal year 2014 and 11 purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal years 2014-2019. The expenses associated with the winter purchases for 2013, 2012 and 2011 were $43.1 million, $43.4 million and $43.4 million, respectively. The expense associated with Tier 2 purchases were $23.4 million and $8.5 million for fiscal years 2013 and 2012, respectively. 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.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Pacific Northwest Electric Power Planning and Conservation Act to meet the net firm power load requirements of its customers in the Pacific Northwest. BPA is authorized to help meet its net firm power load through the acquisition of electric conservation measures. BPA makes available a portfolio of initiatives and infrastructure support activities to its customers to ensure the conservation targets established in the Northwest Power and Conservation Council's Sixth Power Plan are achieved. These initiatives and activities are often executed via long-term conservation commitments made by BPA to its customers. These commitments are captured through $174.7 million of agreements with utility customers and contractors that provide support in the way of energy efficiency program research, development and implementation. The timing of the payments under these commitments is not fixed or determinable and these agreements will expire at various dates through fiscal year 2016.

1989 ENERGY NORTHWEST LETTER AGREEMENT

In 1989, BPA agreed with Energy Northwest that in the event any participant shall be unable, for any reason, or shall refuse to pay to Energy Northwest any amount due from such participant under its net billing agreement (for which a net billing credit or cash payment to such participant has been provided by BPA), BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest.

NUCLEAR INSURANCE

BPA is a member of the Nuclear Electric Insurance Limited (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 $10.9 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $15.9 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $4.4 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. As of Sept. 30, 2013, there have been no assessments to BPA under either of these programs.

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 as discussed below. BPA has recorded a liability of $28.5 million on the basis that all conditions have been met except the final resolution in the California refund proceedings and related litigation which management considers probable. However, interest payable has not been recorded because the amount that will be paid cannot be reasonably estimated. 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 Ninth Circuit Court found that governmental utilities, like BPA, were not subject to FERC's statutory refund authority. As a consequence of the Ninth Circuit 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 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.

In May 2012, the Court of Federal Claims issued an opinion in the trial on liability issues and held that BPA breached its contracts with the California parties by failing to pay refunds for amounts owed in excess of the mitigated market clearing prices during the refund period. BPA estimates that such refund amounts, including interest, through Sept. 30, 2013, could amount up to approximately $54.1 million. While this ruling does not establish a specific liability in this matter, BPA recorded a liability in this amount.

The plaintiffs' contractual breach claims were premised in part upon a November 2009 order where FERC found that as a consequence of establishing a new just and reasonable rate for the purpose of calculating refunds for jurisdictional utilities, it also retroactively reset the prices under the ISO and PX tariffs for all market participants. BPA separately appealed the November 2009 order to the Ninth Circuit Court. In August 2012, subsequent to the ruling of the Court of Federal Claims described above, the Ninth Circuit Court issued a decision on this appeal and held that establishing a new price for purposes of calculating refunds did not retroactively revise the rate for all market participants. The United States Department of Justice, representing BPA in this matter, filed a motion to reconsider the May 2012 decision of the Court of Federal Claims based upon this recent Ninth Circuit Court ruling. On April 2, 2013, the Court of Federal Claims denied the motion for reconsideration.

In a separate proceeding at FERC as part of the California refund docket, an administrative law judge appointed by the FERC Commissioners conducted a hearing in 2012 to make certain findings related to three additional classes of transactions ("summer 2000, exchange, and multi-day"). On Feb. 15, 2013, the FERC administrative law judge issued the initial decision on the summer 2000, exchange, and multi-day transactions to the FERC Commissioners. As part of his findings, the FERC administrative law judge determined that BPA violated the tariff with 84 summer 2000 transactions and that prices charged for the exchange and multi-day transactions were unjust and unreasonable and are subject to refund. The initial decision has been appealed to the commissioners and is advisory to them. The FERC administrative law judge recommended BPA pay $15.1 million for multi-day transactions and $44.5 million for exchange transactions, plus interest. However, BPA liability for those amounts would not ripen unless the Commissioners adopt the initial decision and the related April 2, 2013 Court of Federal Claims order (mentioned below) stands. While the administrative judge made findings of summer period tariff violations by BPA, he did not make any recommendation regarding refund amounts related to them. When the Commissioners established the hearing, they stated that when they receive the administrative law judge's factual determinations regarding the summer period, they will decide the further steps to be taken. BPA does not believe the initial decision is defensible and filed a Brief on Exceptions on April 11, 2013, in an effort to overturn it. FERC will consider all the parties' arguments and issue a Final Decision.

The California parties filed separate motions with the Court of Federal Claims requesting a ruling on their declaratory relief claims for the summer 2000, exchange and multi-day transactions. On April 2, 2013, the Court of Federal Claims issued a Declaratory Judgment in favor of the California parties' relief claims.

A trial on the damages phase of the proceedings at the Court of Federal Claims was scheduled for June 2013, but has been delayed due to the retirement of the presiding judge. In April 2013, a new judge was appointed to preside over the cases. The new judge indicated that she will be reviewing all of the prior decisions in these proceedings before rescheduling the trial on the damages phase of the case. BPA has not adjusted its liability for the California parties' refund claims as a result of the events occurring at the FERC and the Court of Federal Claims during fiscal year 2013 on the basis that management has determined that it is not probable that such events will ultimately result in an increase in liabilities already recorded in connection with resolution of the California parties' refund claims.

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 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 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 2011. In October 2011, two petitions challenging the 2012 Settlement Agreement were filed. BPA settled with one petitioner and the remaining petitioner pursued its appeal. On October 28, 2013, the Ninth Circuit Court issued an opinion in which it upheld BPA's decision to adopt the 2012 Settlement Agreement. This decision is still subject to rehearing.

The 2012 Settlement Agreement completely replaced and superseded BPA's REP-related decisions in the WP-07 Supplemental Rate Case and WP-10 Rate Case. In 2011, BPA and many consumer-owned utilities filed respective motions in the Ninth Circuit Court to dismiss pending litigation challenging those decisions on the grounds that such challenges were moot due to the 2012 Settlement Agreement. Consideration of these motions has been stayed pending resolution of the challenge to the 2012 Settlement Agreement. As described above, the Court issued a decision on October 28, 2013, affirming BPA's decision to adopt the 2012 Settlement Agreement, but such decision is still subject to rehearing.

The cost of providing REP benefits will be recovered through future rates. BPA has recorded regulatory assets, a liability and a regulatory liability for the effects of the 2012 Settlement Agreement. (See Note 10, 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 2013.

Judgments and settlements are included in BPA's costs and recovered through rates. Except with respect to the SCE, California parties' refund claims, and REP matters described above, BPA has not recorded a liability for the above legal matters. (See Note 11, Deferred Credits and Other, for discussion of amounts accrued for outstanding legal claims and settlements.)

Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Thousands of dollars)

	As of June 30, 2014	As of September 30, 2013
Assets		
Utility plant		
Completed plant	$ 16,371,588	$ 16,153,536
Accumulated depreciation	(5,895,841)	(5,700,821)
	10,475,747	10,452,715
Construction work in progress	1,627,247	1,344,033
Net utility plant	12,102,994	11,796,748
Nonfederal generation	3,390,595	3,243,713
Current assets		
Cash and cash equivalents	1,286,960	1,010,128
Short-term investments in U.S. Treasury securities	474,580	388,914
Accounts receivable, net of allowance	28,359	29,540
Accrued unbilled revenues	302,380	260,757
Materials and supplies, at average cost	111,007	112,019
Prepaid expenses	75,901	40,458
Total current assets	2,279,187	1,841,816
Other assets		
Regulatory assets	6,758,514	6,953,397
Investments in U.S. Treasury securities	118,801	34,961
Nonfederal nuclear decommissioning trusts	280,460	254,752
Deferred charges and other	397,702	146,682
Total other assets	7,555,477	7,389,792
Total assets	$ 25,328,253	$ 24,272,069
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	$ 2,920,272	$ 2,432,217
Federal appropriations	4,345,839	4,291,457
Borrowings from U.S. Treasury	3,974,040	3,738,040
Nonfederal debt	6,075,770	6,229,004
Total capitalization and long-term liabilities	17,315,921	16,690,718
Commitments and contingencies (See Note 14 to 2013 Audited Financial Statements)		
Current liabilities		
Borrowings from U.S. Treasury	313,000	147,000
Nonfederal debt	1,123,189	607,865
Accounts payable and other	522,902	503,112
Total current liabilities	1,959,091	1,257,977
Other liabilities		
Regulatory liabilities	2,351,785	2,434,065
IOU exchange benefits	2,814,574	2,992,740
Asset retirement obligations	176,690	171,554
Deferred credits and other	710,192	725,015
Total other liabilities	6,053,241	6,323,374
Total capitalization and liabilities	$ 25,328,253	$ 24,272,069

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Fiscal Year-to-Date Ended June 30, 2014	Fiscal Year-to-Date Ended June 30, 2013
Operating revenues				
Sales	**$ 896,708**	$ 800,516	**$ 2,645,474**	$ 2,445,225
U.S. Treasury credits for fish	**9,294**	20,452	**90,814**	67,073
Miscellaneous revenues	**15,576**	18,350	**49,717**	55,897
Total operating revenues	**921,578**	839,318	**2,786,005**	2,568,195
Operating expenses				
Operations and maintenance	**467,679**	462,076	**1,363,089**	1,385,224
Purchased power	**12,237**	19,106	**161,862**	126,326
Nonfederal projects	**(128,330)**	180,007	**256,243**	539,994
Depreciation and amortization	**110,646**	105,259	**329,796**	315,705
Total operating expenses	**462,232**	766,448	**2,110,990**	2,367,249
Net operating revenues	**459,346**	72,870	**675,015**	200,946
Interest expense and (income)				
Interest expense	**91,027**	91,966	**240,336**	261,469
Allowance for funds used during construction	**(12,239)**	(11,025)	**(36,919)**	(32,905)
Interest income	**(6,944)**	(10,702)	**(16,457)**	(20,639)
Net interest expense	**71,844**	70,239	**186,960**	207,925
Net revenues (expenses)	**$ 387,502**	$ 2,631	**$ 488,055**	$ (6,979)

Independent Auditor's Report

To the Executive Board of Energy Northwest:

We have audited the statements of net position and the related statements of revenues, expenses and changes in net position and of cash flows of 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 as of and for the year ended June 30, 2013, and the related notes to the financial statements, which collectively comprise the business-type activities of Energy Northwest (the "Company").

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express opinions on the financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities of the Company at June 30, 2013, and the respective results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matter

The accompanying management's discussion and analysis listed in the table of contents are required by accounting principles generally accepted in the United States of America to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in the appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

PricewaterhouseCoopers LLP

Portland, Oregon
September 26, 2013

Energy Northwest Management's Discussion and Analysis

Energy Northwest is a municipal corporation and joint operating agency of the state of Washington. Each Energy Northwest business unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by business unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the fiscal year (FY) ended June 30, 2013, with the basic financial statements for the fiscal year ended June 30, 2012.

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.)

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 2013 and FY 2012 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, 2013 and 2012 (Dollars in thousands)

		2012		2013		Change
Assets						
Current Assets	$	209,345	$	199,122	$	(10,223)
Restricted Assets						
Special Funds		51,345		51,896		551
Debt Service Funds		516,106		672,455		156,349
Net Plant		1,525,642		1,499,711		(25,931)
Nuclear Fuel		341,535		985,824		644,289
Other Charges		3,658,124		3,258,111		(400,013)
TOTAL ASSETS	**$**	**6,302,097**	**$**	**6,667,119**	**$**	**365,022**
Current Liabilities	$	501,801	$	621,867	$	120,066
Restricted Liabilities						
Special Funds		138,406		147,047		8,641
Debt Service Funds		144,557		139,029		(5,528)
Long-Term Debt		5,508,467		5,746,882		238,415
Other Long-Term Liabitilies		15,776		18,115		2,339
Other Credits		5,709		5,727		18
Net Position		(12,619)		(11,548)		1,071
TOTAL LIABILITIES AND NET POSITION	$	**6,302,097**	$	**6,667,119**	$	**365,022**
Operating Revenues	$	425,695	$	569,863	$	144,168
Operating Expenses		354,860		443,629		88,769
Net Operating Revenues		70,835		126,234		55,399
Other Income and Expenses		(71,049)		(125,163)		(54,114)
(Distribution) & Contribution		-		-		-
Beginning Net Assets		(12,405)		(12,619)		(214)
ENDING NET ASSETS	$	**(12,619)**	$	**(11,548)**	$	**1,071**

Columbia Generating Station

Columbia Generating Station (Columbia) is wholly owned by Energy Northwest and its participants and operated by Energy Northwest. The plant is a 1,170-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, Washington.

Columbia produced 8,479 gigawatt-hours (GWh) of electricity in FY 2013, as compared to 6,984 GWh of electricity in FY 2012, which included economic dispatch of 51 and 140 GWh respectively. Columbia entered its planned refueling outage (R-21) on May 11, 2013. The 40 day planned outage extended an additional 5 days and ended June 25, 2013. The FY 2013 generation increase of 21.4% was due to the extended outage (R-20) incurred in FY 2011 extending into a portion of FY 2012, which ended September 27, 2012 which reduced the amount of power generated in FY 2012. Additionally, FY 2013 generation was approximately 6 GWh higher than budgeted, reflecting the continuous and successful generation run.

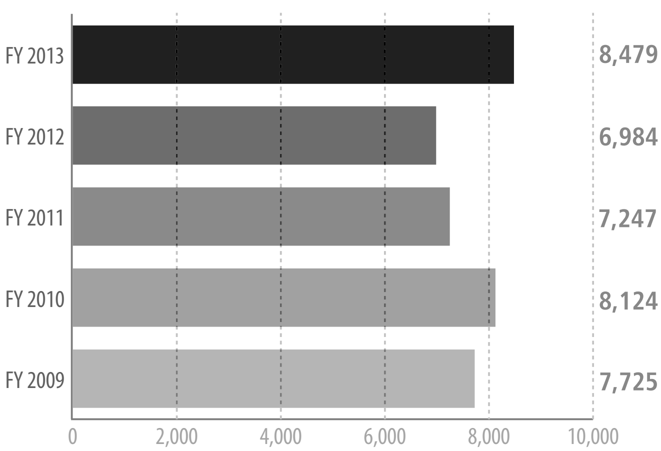
Columbia's cost performance is measured by the cost of power indicator. The cost of power for FY 2013 was 4.51 cents per kilowatt-hour (kWh) as compared with 4.73 cents per kWh in FY 2012. The industry cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. The FY 2013 cost of power decrease of 4.7 percent was due to the successful cost control and generation run in FY 2013 as compared to the generation and additional costs incurred during FY 2012 due to the extended R-20 outage.

Balance Sheet Analysis

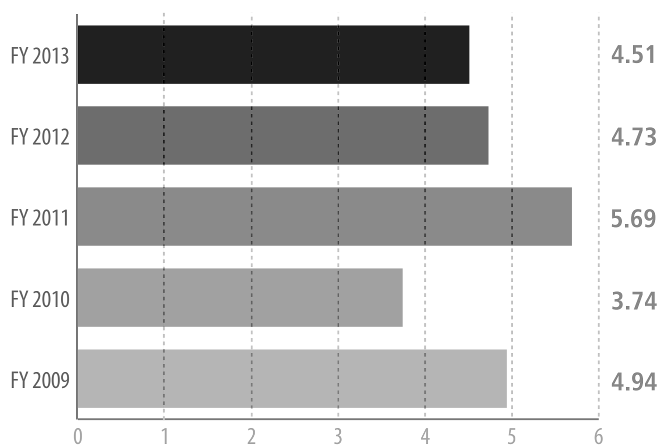
The net decrease to Utility Plant (plant) and Construction Work In Progress (CWIP) from FY 2012 to FY 2013 (excluding nuclear fuel) was $18.1 million. The changes to plant and CWIP were comprised of additions to plant of $8.0 million with an increase to CWIP of $55.9 million. Remaining changes was the period effect of depreciation of $82.0 million. The accumulated decommissioning and site restoration accrued costs related to the Integrated Spent Fuel Storage Installation (ISFSI) at Columbia were adjusted to reflect the change in the asset retirement obligation (ARO). Change in the ARO was necessary due to new Nuclear Regulatory Commission requirements for fuel storage calculations. Per ASC 410, "Asset Retirement and Environmental Obligations," the obligation was reevaluated and adjusted to reflect the change in timing due to the relicensing of Columbia through December 31, 2043 and to account for estimated costs related to fuel disposition obligations for the post five year period following the end of licensing and generation. The revision resulted in an increase to the capitalized portion of the asset of $0.5 million. (See Note 11 to the Financial Statements.)

The FY 2013 additions to CWIP of $55.9 million consisted of 20 major projects of at least $0.7 million: Fukushima impacts, Radio Obsolescence, Cobalt Reduction Program, Stack Monitor Performance, Service Water Pump and Motor Overhaul, On-Line Noble Chemical Application, Keep Fill Pump Replacement, Control Rod Device Refurbishment, Main Transformer Replacement, High Pressure Core Spray Refurbishment, Turbine Blade Procurement, Reactor Feed Water Overhaul, Condensate Pump Refurbishment, Residual Heat Removal Systems, and Plant Telephone Obsolescence. These projects resulted in 76

Columbia Generating Station
NET GENERATION - GWhrs



Columbia Generating Station
COST OF POWER - Cents/kWh



percent of the CWIP activity. The remaining 24 percent were made up of 103 separate projects.

Nuclear fuel, net of accumulated amortization, increased $644.3 million from FY 2012 to $985.8 million for FY 2013. The major factor contributing to the increase in Nuclear Fuel relates to the completion of the Depleted Uranium Enrichment Program (DUEP). This program increased Fuel held for resale from $1.5 million in FY 2012 to $538.9 million in FY 2013. Fuel amounts used for reload increased $90.0 million with a decrease in net fuel of $37.8 million for current year amortization. Fuel removed for cooling increased $55.3 million and remaining change was $0.6 million for fuel loan and purchase activity relating to the cylinder/sampling activity for the DUEP.

Current assets increased $16.4 million in FY 2013 to $166.2 million. Changes were increases to materials and supplies of $10.2 million (nuclear fuel cask inventory is $4.5 million and inventory is $5.7), increases to cash and investments of $7.2 million offset by a decrease in accounts and other receivables of $1.0 million.

Special funds decreased $20.4 million to $16.4 million in FY 2013 due to the FY 2013 bond activity and schedule of construction costs for these funds in FY 2013.

The debt service funds increased $57.6 million in FY 2013 to $147.5 million. The increase is due to the maturity of outstanding debt along with restructuring and funding activities and the requirement of making funds available for these maturities.

Deferred charges increased $59.8 million in FY 2013 from $835.0 million to $894.8 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 $58.1 million. There was also a slight increase to unamortized debt expense of $1.7 million due to debt related activity.

Current liabilities increased $15.6 million in FY 2013 to $139.6 million. Components of the change were an increase to year end obligations relating from R-21 year end impacts of $4.1 million, increases to current maturities of debt of $60.7 million, decrease of $61.8 million due to payment of notes payable obligation related to the DUEP, an increase of $14.6 million for business unit activity and a decreased requirement for participant amounts under the net billing agreement of $2.0 million.

Restricted liabilities increased $12.5 million in FY 2013 to $198.7 million. The increase was due to bond activity and related increase of $5.7 million and decommissioning increases of $6.8 million.

Long-term debt (Bonds Payable) increased $721.6 million in FY 2013 from $2.4 billion to $3.2 billion due to the debt associated with DUEP of $748.6 million. The current portion of Bonds Payable increased $60.1 million, which was driven by timing of scheduled maturities.

Other long-term liabilities increased $2.1 million in FY 2013 to $17.9 million related to nuclear fuel cask activity.

Statement of Operations Analysis

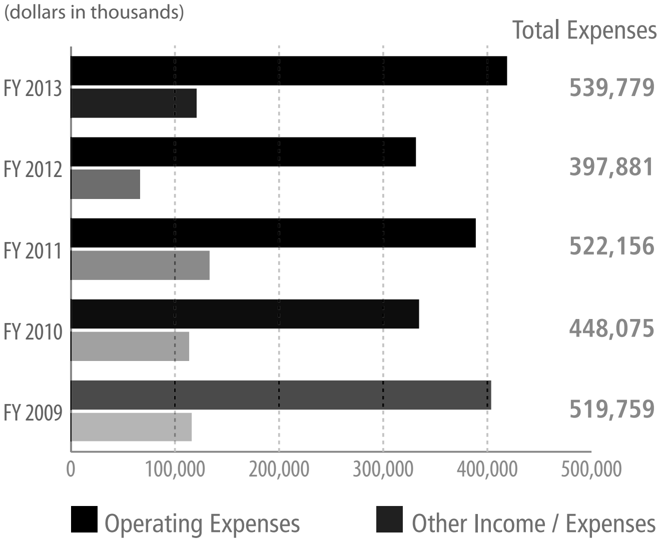
Columbia is a net-billed project. Energy Northwest recognizes revenues equal to expenses for each period on net-billed projects. No net revenue or loss is recognized and no net assets are accumulated.

Operating expenses increased $87.5 million from FY 2012 costs of $331.4 million to $418.9 million in FY 2013. The increases in costs were due to FY 2013 being a planned refueling year. The majority of the impacts to operating expenses were for Operations and Maintenance costs. These costs were $68.9 million higher in FY 2013. Increased generation in FY 2013 resulted in increased fuel disposal costs of $8.5 million and increased generation taxes of $0.8 million. Periodic expenses for depreciation and decommissioning increased $8.4 million with the remainder of the increase ($0.9 million) a result of Administrative and General Expenses.

Other Income and Expenses increased $54.2 million from FY 2012 to $120.7 million net expenses in FY 2013. In FY 2012 there was a spent fuel litigation settlement from the Department of Energy (DOE) of $48.7 million recorded as an offset to other income and expense. This is the major factor in the overall increase in other income and expenses for FY 2013. Additionally, FY 2012 had $1.8 million in property disposal gains (condenser from R-20) that did not occur in FY 2013. The remaining major components of the increases were $2.0 million due to bond and interest related activity and decreases to leasing activity of $1.7 million. This includes a $1.2 million DUEP leasing adjustment.

Columbia's total operating revenue increased from $397.9 million in FY 2012 to $539.7 million in FY 2013. The increase in costs (and conversely revenue per net billing) of $141.8 million was due to the increased costs incurred in the completion of R-21. R-21 was originally budgeted for $87.0 million and 40 days. Actual cost and days were $85.1 million and 45 days. Columbia officially synced to the grid on June 25, 2013 signaling the completion of R-21.

Columbia Generating Station
TOTAL OPERATING COSTS
(dollars in thousands)



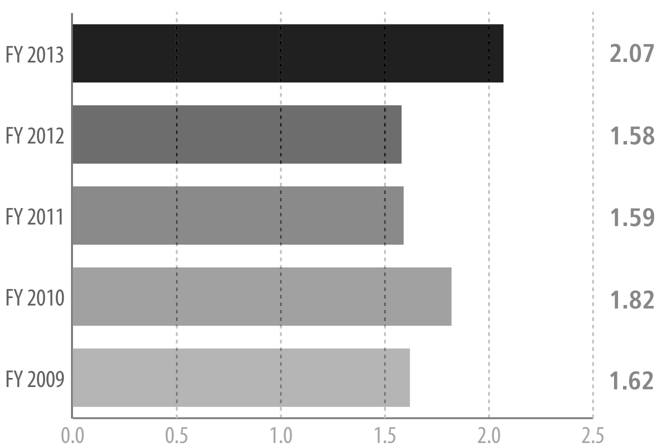
C-5

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, Washington. 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 103.70 GWh of electricity in FY 2013 versus 119.43 GWh in FY 2012. The 13.2 percent decrease in generation can be attributed to less favorable water availability compared to the previous year in addition to FY 2012 being the fourth highest generation in the life of the plant. Generation results for FY 2013 did exceed the estimated amount of 92.7 GWh by 11.9 percent.

Packwood's cost performance is measured by the cost of power indicator. The cost of power for FY 2013 was $2.07 cents per kWh as compared to $1.58 cents per kWh in FY 2012. The cost of power fluctuates year-to-year depending on various factors such as outage, maintenance, generation, and other operating costs. The FY 2013 cost of power increase of 31.0 percent was a result of less generation due to water availability and increased costs due to maintenance and transmission charges.

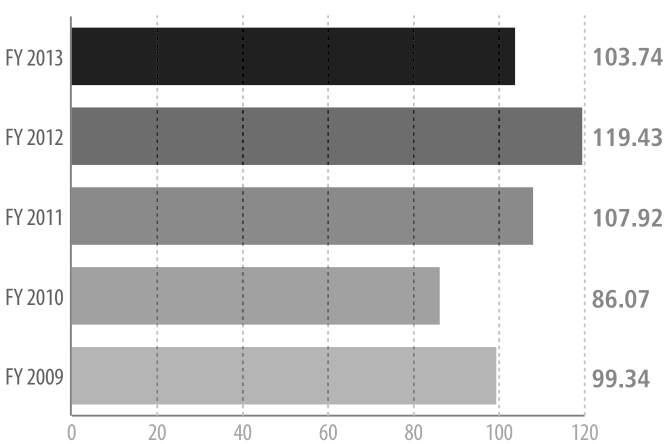
Packwood Lake Hydroelectric Project
COST OF POWER - Cents/kWh



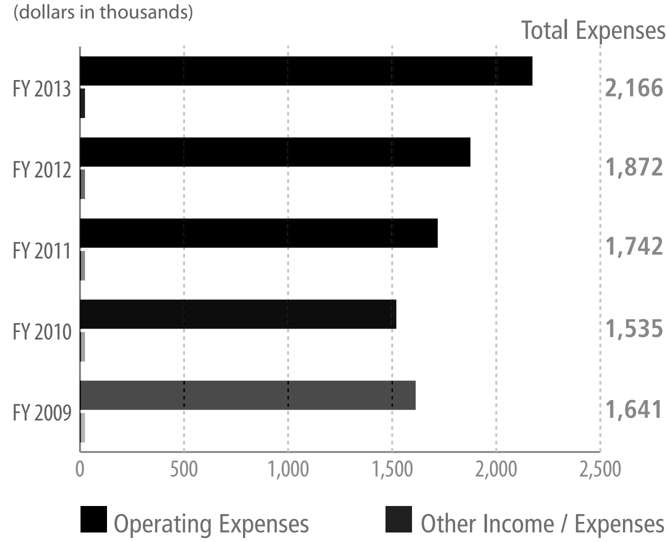
Balance Sheet Analysis

Total assets decreased $0.1 million from FY 2012, with the drivers being an increase of $0.7 million in capital activity for utility plant and a decrease of $0.8 million in cash for operating activities. The corresponding decrease to total liabilities of $0.1 million was the decrease in due to participants for the results of operations. Packwood has incurred $3.7 million in relicensing costs through FY 2012 with no new costs incurred for FY 2013. 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, 2013, Packwood continues to be relicensed under this extended agreement.

Packwood Lake Hydroelectric Project
NET GENERATION - GWhrs



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



C-6

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 net assets are accumulated.

Operating expenses increased $0.3 million to $2.2 million in FY 2013 from $1.9 million in FY 2012. Operations and Maintenance was the major reason for the increase due to increased transmission and scheduling costs of $57,000 and $245,000 of hydraulic and electrical expenses.

Other Income and Expense increased from a net gain of $4,000 in FY 2012 to an $8,000 gain in FY 2013. The $4,000 increase in net gain is primarily due to a small gain on property disposed of $2,000 and a small increase in investment income from FY 2012 of $2,000.

Packwood participants are obligated to pay annual costs of the project (including any applicable debt service), whether or not the project is operable. The Packwood participants also share project revenue to the extent that the amounts exceed costs. These funds can be returned to the participants or kept within the project. As of June 30, 2013 there is $5.7 million recorded as deferred revenues in excess of costs that are being kept within the project. Packwood participants are currently taking 100 percent of the project generation; there are no additional agreements for power sales.

Nuclear Project No. 1

Energy Northwest wholly owns Nuclear Project No. 1, a 1,250-MWe plant, which 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 of Nuclear Project No. 1 and are net-billed.

Balance Sheet Analysis

Long-term debt decreased $289.7 million from $1.4 billion in FY 2012 to $1.1 billion in FY 2013 as a result of $273.1 million being transferred to current debt to be paid on July 1, 2013 along with a decrease in bond related amortization of $16.6 million. Short term debt increased $37.0 million per the debt maturity schedule. There was a decrease to restricted liabilities of $7.0 million, represented by a decrease to interest payable of $8.8 million offset by an increase to the decommissioning estimate of $1.8 million.

Statement of Operations Analysis

Other Income and Expenses showed a net decrease to expenses of $20.0 million from $75.0 million in FY 2012 to $55.0 million in FY 2013. Investment revenue stayed steady, bond related expenses decreased $21.5 million, decommissioning costs increased $1.3 million and there was a slight increase of $0.2 million in plant preservation 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 the responsibility of Energy Northwest and are net-billed. (See Note 13 to the Financial Statements.)

Balance Sheet Analysis

Long-term debt decreased $174.4 million from $1.5 billion in FY 2012 to $1.3 billion in FY 2013, as a result of $166.2 million being transferred to current debt to be paid on July 1, 2013 along with a decrease in bond related amortization of $8.2 million. Current debt per the debt maturity schedule increased $70.6 million from $95.5 million in FY 2012 to $166.2 million in FY 2013. The remaining changes in liabilities of $6.6 million were due to increased payable transfers from bond related activities.

Statement of Operations Analysis

Overall expenses decreased $9.9 million from FY 2012 related to bond activity with investment income and liquidation costs 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 increased $1.0 million from $9.1 million in FY 2012 to $10.1 million in FY 2013. Increases were due to cash and investments of $1.1 million, net plant of $0.2 million, and decreases to receivables and prepaid amounts of $0.3 million. Liabilities decreased $0.4 million from FY 2012 due to timing of year end outstanding items.

Statement of Operations Analysis

Operating Revenues in FY 2013 totaled $9.0 million as compared to FY 2012 revenues of $9.8 million, a decrease of $0.8 million. The decrease in revenues was driven by four major projects: Grays Harbor project, which was a 50 MW power call option that ended in June 2013 at the 600 MW Satsop Natural Gas Combined-Cycle plant as part of a compensation package for selling development rights to Duke Energy in 2001 ($0.3 million), termination of the Kalama project in FY 2013, which was a proposed development of a 346 MW Natural Gas Combined-Cycle plant in southwestern Washington state ($0.4 million), decreases in Hanford calibration services ($0.3 million) due to the expiration of a portion of the contracted scope of work, and decreased lease activity ($0.3 million). The decreases in the four projects mentioned above were offset by increased revenues for technical services and engineering services of $0.6 million. Operating costs decreased $0.9 million due to decreased business activity resulting in a net operating increase of $0.1 million.

Other Income and Expenses decreased $0.2 million from $1.5 million in net revenues in FY 2012 to net revenue of $1.3 million in FY 2013; there was an adjustment of $0.1 million for completion of the power option derivative contract for the Grays Harbor project, and a decrease of other income and expenses of $0.1 million, with no significant individual items.

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 2013 there were no contributions (transfers), which was also the case for FY 2012.

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 are 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 average homes.

Nine Canyon produced 228.23 GWh of electricity in FY 2013 versus 261.63 GWh in FY 2012. The decrease of 12.8 percent was due to slightly less favorable wind conditions in FY 2013 as compared to FY 2012. The average wind speed for the months of January and June were significantly below the 10 year average. The below average wind conditions combined with FY 2012 being the second highest generation year for history of the project were the drivers for the decrease between years.

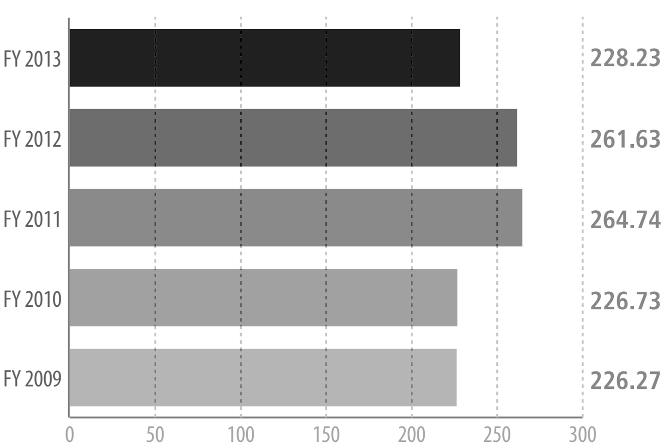
Nine Canyon's cost performance is measured by the cost of power indicator. The cost of power for FY 2013 was $7.91 cents per kWh as compared to $6.69 cents per kWh in FY 2012. The cost of power fluctuates year to year depending on various factors such as wind totals and unplanned maintenance. The FY 2013 cost of power increase of 18.2 percent was a result of the decreased generation due to wind conditions and higher maintenance costs incurred due to turbine bearing maintenance.

Balance Sheet Analysis

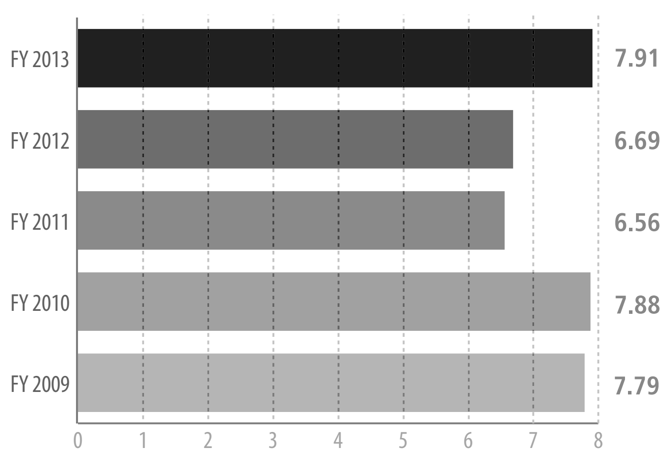
Total assets decreased $5.0 million from $119.5 million in FY 2012 to $114.5 million in FY 2013. The major driver for the change in assets was a decrease of $6.8 million in net plant due to accumulated depreciation. The remaining changes consisted of increases to restricted assets of $2.4 million and decreases in cash and investments of $0.2 million, prepaid amounts of $0.2 million and debt related expenses of $0.2 million. There was an overall decrease to liabilities of $5.2 million with a decrease to long term debt of $7.4 million, increases to current debt maturities of $2.3 million, increases to accrued debt related interest of $0.1 million, and increases to accrued costs and business activities of $0.1 million. The increase in net assets was $0.2 million in FY 2013 as compared to a decrease of $1.3 million in FY 2012. The slight reversal in net assets reflects the rate stabilization approach for Nine Canyon planning out through the 2030 period.

In previous years Energy Northwest has accrued, as income (contribution) from the Department of Energy, Renewable Energy Production Incentive (REPI) payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI legislation. 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. 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. 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 Wind Project
NET GENERATION - GWh



Nine Canyon Wind Project
COST OF POWER - Cents/kWh

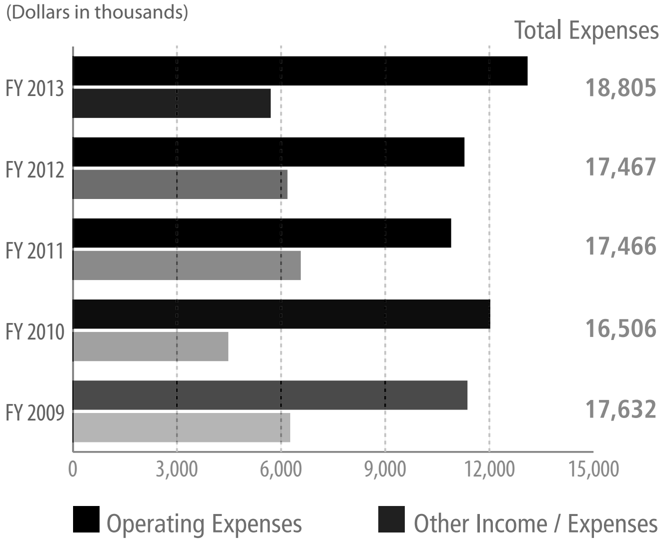


Nine Canyon participants increased 69 percent and 80 percent for Phase I and Phase II participants respectively in FY 2008 in order to cover total project costs, projected out to the 2030 proposed project end date. The increases for FY 2008 were a change from the previous plan where a 3 percent increase 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 increased 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 funding, similar to Phase I and II.

Nine Canyon Wind Project

TOTAL OPERATING COSTS

(Dollars in thousands)



Statement of Operations Analysis

Operating revenues increased $2.8 million from $16.2 million in FY 2012 to $19.0 million in FY 2013. The project received revenue from the billing of the purchasers at an average rate of $80.06 per MWh for FY 2013 as compared to $61.98 per MWh for FY 2012 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 increased operating revenues from the previous year were due to increased funding requirements for Phase III purchasers. The increase in the average rate billed to purchasers was also impacted by the reduced generation in FY 2013 as compared to FY 2012. Operating costs increased from $11.3 million in FY 2012 to $13.1 million in FY 2013. Increased operating costs of $1.8 million for FY 2013 were due to maintenance work related to turbine bearing replacements.

Other income and expenses decreased $0.5 million from $6.2 million in net expenses FY 2012 to $5.7 million in FY 2013. Decreased interest costs of $0.4 million and decreases in amortized bond expenses of $0.1 million accounted for the change. Net gain or change in net assets of $0.2 million for FY 2013 was a direct result of the planned average rate increase with lower than budgeted operating costs.

The original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires. The REPI incentive expires 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 2013 and is not anticipating receiving any future REPI incentives. The results from FY 2013 reflect the revised rate plan scenario and gradual increase in the return of total net assets.

Internal Service Fund

The Internal Service Fund (ISF) (formerly the General Fund) was established in May 1957. The ISF 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 increased $9.1 million from $46.6 million in FY 2012 to $55.7 million in FY 2013. The five major items contributing to the change were 1) decreases to net plant of $2.0 million, 2) decrease of $5.7 million to cash to reflect FY 2013 recognition of year-end check redemption related to R-21 versus the requirements of FY 2012 which was a non-outage year, 3) an increase of $1.6 million in restricted assets due to the debt maturity schedule and escrow requirements processing schedule, 4) an increase to prepaid amounts of $0.4 million, and an increase to due from other business units of $14.8 million.

The net increase in net assets and liabilities is due to increases in accounts payable and payroll related liabilities of $9.4 million due to year-end timing of expenses for FY 2013, which was an outage year and a decrease of $15.0 million due to other business units resulting from the change in year-end activities.

Statement of Operations Analysis

Net revenues for FY 2013 increased $112,000 from FY 2012. The increase was due to decreased amounts of other business expenses of $146,000, decrease in depreciation of $194,000 offset by decreases in operating revenue due to operations of $452,000.

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)	Aa1	A2	A2
Standard and Poor's Ratings Services (S & P)	AA-	A-	A

Statement Of Net Position As of June 30, 2013 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project Number 1*	Nuclear Project Number 3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	Combined Total
ASSETS									
CURRENT ASSETS									
Cash	$ 33,154	$ 373	$ 606	$ 667	$ 5,223	$ 8,624	$ 48,647	$ -	$ 48,647
Available-for-sale investments	10,000	1,023	2,512	2,669	2,542	1,049	19,795	5,065	24,860
Accounts and other receivables	263	111	3	3	466	144	990	84	1,074
Due from other business units	-	10	270	-	343	-	623	16,638	-
Materials and supplies	121,404	-	-	-	-	-	121,404	-	121,404
Prepayments and other	1,409	12	-	-	140	76	1,637	1,500	3,137
TOTAL CURRENT ASSETS	**166,230**	**1,529**	**3,391**	**3,339**	**8,714**	**9,893**	**193,096**	**23,287**	**199,122**
RESTRICTED ASSETS (NOTE 1)									
Special funds									
Cash	9,907	-	298	699	-	4	10,908	406	11,314
Available-for-sale investments	6,518	-	3,000	7,257	-	1,558	18,333	22,227	40,560
Accounts and other receivables	22	-	-	-	-	-	22	-	22
Debt service funds									
Cash	125,970	-	98,267	57,632	-	9,959	291,828	-	291,828
Available-for-sale investments	21,482	-	207,975	139,799	-	11,364	380,620	-	380,620
Accounts and other receivables	3	-	-	3	-	1	7	-	7
TOTAL RESTRICTED ASSETS	**163,902**	**-**	**309,540**	**205,390**	**-**	**22,886**	**701,718**	**22,633**	**724,351**
NON CURRENT ASSETS									
UTILITY PLANT (Note 2)									
In service	3,813,536	14,437	-	-	2,543	134,510	3,965,026	47,971	4,012,997
Not in service	-	-	29,415	-	-	-	29,415	-	29,415
Construction work in progress	116,483	-	-	-	-	-	116,483	-	116,483
Accumulated depreciation	(2,523,438)	(12,812)	(29,415)	-	(1,150)	(54,166)	(2,620,981)	(38,203)	(2,659,184)
Net Utility Plant	1,406,581	1,625	-	-	1,393	80,344	1,489,943	9,768	1,499,711
Nuclear fuel, net of accumulated depreciation	985,824	-	-	-	-	-	985,824	-	985,824
LONG TERM RECEIVABLES	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL NONCURRENT ASSETS	**2,392,405**	**1,625**	**-**	**-**	**1,393**	**80,344**	**2,475,767**	**9,768**	**2,485,535**
OTHER CHARGES									
Cost in excess of billings	880,778	-	1,093,010	1,258,171	-	-	3,231,959	-	3,231,959
Unamortized debt expense	14,290	-	2,813	3,888	-	1,424	22,415	-	22,415
Other	-	3,737	-	-	-	-	3,737	-	3,737
TOTAL OTHER CHARGES	895,068	3,737	1,095,823	1,262,059	-	1,424	3,258,111	-	3,258,111
TOTAL ASSETS	**$ 3,617,605**	**$ 6,891**	**$ 1,408,754**	**$ 1,470,788**	**$ 10,107**	**$ 114,547**	**$ 6,628,692**	**$ 55,688**	**$ 6,667,119**

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

Statement Of Net Position As of June 30, 2013 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project Number 1*	Nuclear Project Number 3*	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	Combined Total
LIABILITIES AND NET ASSETS									
CURRENT LIABILITIES									
Current maturities of long-term debt	$ 61,020	$ -	$ 273,055	$ 166,160	$ -	$ 6,835	$ 507,070	$ -	$ 507,070
Accounts payable and accrued expenses	36,973	196	183	43	995	486	38,876	49,994	88,870
Due to participants	24,959	968	-	-	-	-	25,927	-	25,927
Due to other business units	16,618	-	-	10	-	10	16,638	623	-
TOTAL CURRENT LIABILITIES	**139,570**	**1,164**	**273,238**	**166,213**	**995**	**7,331**	**588,511**	**50,617**	**621,867**
LIABILITIES-PAYABLE FROM RESTRICTED ASSETS (NOTE 1)									
Special funds									
Accounts payable and accrued expenses	127,163	-	18,244	-	-	1,287	146,694	353	147,047
Debt service funds									
Accrued interest payable	71,522	-	33,186	31,259	-	3,062	139,029	-	139,029
TOTAL RESTRICTED LIABILITIES	**198,685**	**-**	**51,430**	**31,259**	**-**	**4,349**	**285,723**	**353**	**286,076**
LONG-TERM DEBT (NOTE 5)									
Revenue bonds payable	3,163,020	-	1,048,005	1,229,245	-	124,120	5,564,390	-	5,564,390
Unamortized (discount)/ premium on bonds - net	105,591	-	36,251	44,955	-	4,138	190,935	-	190,935
Unamortized loss on bond refundings	(7,175)	-	(170)	(884)	-	(214)	(8,443)	-	(8,443)
TOTAL LONG-TERM DEBT	**3,261,436**	**-**	**1,084,086**	**1,273,316**	**-**	**128,044**	**5,746,882**	**-**	**5,746,882**
OTHER LONG-TERM LIABILITIES	**17,914**	**-**	**-**	**-**	**195**	**-**	**18,109**	**6**	**18,115**
OTHER CREDITS									
Advances from members and others	-	5,727	-	-	-	-	5,727	-	5,727
Other	-	-	-	-	-	-	-	-	-
TOTAL OTHER CREDITS	**-**	**5,727**	**-**	**-**	**-**	**-**	**5,727**	**-**	**5,727**
NET POSITION									
Invested in capital assets, net of related debt	-	-	-	-	1,393	(53,110)	(51,717)	9,766	(41,951)
Restricted, net	-	-	-	-	-	17,559	17,559	22,633	40,192
Unrestricted, net	-	-	-	-	7,524	10,374	17,898	(27,687)	(9,789)
NET POSITION	**-**	**-**	**-**	**-**	**8,917**	**(25,177)**	**(16,260)**	**4,712**	**(11,548)**
TOTAL LIABILITIES	**3,617,605**	**6,891**	**1,408,754**	**1,470,788**	**1,190**	**139,724**	**6,644,952**	**50,976**	**6,678,667**
TOTAL LIABILITIES AND NET POSITION	**$ 3,617,605**	**$ 6,891**	**$ 1,408,754**	**$ 1,470,788**	**$ 10,107**	**$ 114,547**	**$ 6,628,692**	**$ 55,688**	**$ 6,667,119**

* 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 Position

As Of June 30, 2013 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Project	Nuclear Project No.1 *	Nuclear Project No.3 *	Business Development Fund	Nine Canyon Wind Project	Subtotal	Internal Service Fund	2013 Combined Total
OPERATING REVENUES	$ 539,667	$ 2,173	$ -	$ -	$ 9,024	$ 18,999	$ 569,863	$ -	$ 569,863
OPERATING EXPENSES									
Services to other business units	-	-	-	-	-	-	-	-	-
Nuclear fuel	42,433	-	-	-	-	-	42,433	-	42,433
Spent fuel disposal fee	8,059	-	-	-	-	-	8,059	-	8,059
Decommissioning	6,306	-	-	-	-	84	6,390	-	6,390
Depreciation and amortization	83,967	57	-	-	240	6,814	91,078	-	91,078
Operations and maintenance	246,376	1,938	-	-	9,167	6,121	263,602	-	263,602
Administrative & general	27,775	164	-	-	-	34	27,973	-	27,973
Generation tax	4,023	22	-	-	-	49	4,094	-	4,094
Total operating expenses	418,939	2,181	-	-	9,407	13,102	443,629	-	443,629
OPERATING INCOME (LOSS)	**120,728**	**(8)**	**-**	**-**	**(383)**	**5,897**	**126,234**	**-**	**126,234**
OTHER INCOME & EXPENSE									
Other	4,785	3	55,032	55,906	1,308	12	117,046	82,214	116,978
Investment income	645	5	68	50	20	61	849	11	849
Interest expense and discount amortization	(126,158)	-	(51,919)	(55,594)	-	(5,776)	(239,447)	-	(239,447)
Plant preservation and termination costs	-	-	(1,336)	(362)	-	-	(1,698)	-	(1,698)
Depreciation and amortization	-	-	(6)	-	-	-	(6)	2,109	(6)
Decommissioning	-	-	(1,839)	-	-	-	(1,839)	-	(1,839)
Services to other business units	-	-	-	-	-	-	-	(84,402)	-
TOTAL OTHER INCOME & EXPENSE	**(120,728)**	**8**	**-**	**-**	**1,328**	**(5,703)**	**(125,095)**	**(68)**	**(125,163)**
INCOME (LOSS)	-	-	-	-	945	194	1,139	(68)	1,071
TOTAL NET ASSETS, BEGINNING OF YEAR	**-**	**-**	**-**	**-**	**7,972**	**(25,371)**	**(17,399)**	**4,780**	**(12,619)**
TOTAL NET ASSETS, END OF YEAR	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,917**	**$ (25,177)**	**$ (16,260)**	**$ 4,712**	**$ (11,548)**

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

Statement of Cash Flows As of June 30, 2013 (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	2013 Combined Total
CASH FLOWS FROM OPERATING AND NON-OPERATING ACTIVITIES								
Operating revenue receipts	$ 478,335	$ 2,011	$ -	$ -	$ 5,074	$ 19,002	$ -	$ 504,422
Cash payments for operating expenses	(275,172)	(2,033)	-	-	(1,159)	(6,069)	-	(284,433)
Non-operating revenue receipts	112	-	338,733	228,232	(67)	-	-	567,010
Cash payments for preservation, termination expense	-	-	(534)	(22)	-	-	-	(556)
Cash payments for services	-	-	-	-	-	-	(4,192)	(4,192)
Net cash provided/(used) by operating and nonoperating activities	203,275	(22)	338,199	228,210	3,848	12,933	(4,192)	782,251
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	785,282	-	-	-	-	-	-	785,282
Payment for bond issuance and financing costs	(4,063)	-	(295)	(306)	(1)	(24)	-	(4,689)
Payment for capital items	(65,339)	(770)	-	-	(333)	(37)	-	(66,479)
Nuclear fuel acquisitions	(679,614)	-	-	-	-	-	-	(679,614)
Interest paid on bonds	(133,511)	-	(75,205)	(64,989)	-	(6,119)	-	(279,824)
Principal paid on revenue bond maturities	(355)	-	(236,030)	(95,540)	-	(4,575)	-	(336,500)
Note Payment	(61,769)	-	-	-	-	-	-	(61,769)
Interest paid on Notes	(110)	-	-	-	-	-	-	(110)
Net cash provided/(used) by capital and related financing activities	(159,479)	(770)	(311,530)	(160,835)	(334)	(10,755)	-	(643,703)
CASH FLOWS FROM NON-CAPITAL FINANCE ACTIVITIES	-	-	-	-	-	-	-	-
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(592,637)	(1,046)	(214,700)	(181,777)	(2,560)	(22,339)	(25,490)	(1,040,549)
Sales of investment securities	615,262	975	194,710	69,005	2,035	28,792	24,640	935,419
Interest on investments	1,794	41	34	31	62	230	(622)	1,570
Net cash provided/(used) by investing activities	24,419	(30)	(19,956)	(112,741)	(463)	6,683	(1,472)	(103,560)
NET INCREASE(DECREASE) IN CASH	**68,215**	**(822)**	**6,713**	**(45,366)**	**3,051**	**8,861**	**(5,664)**	**34,988**
CASH AT JUNE 30, 2012	**100,817**	**1,195**	**92,458**	**104,363**	**2,172**	**9,726**	**6,070**	**316,801**
CASH AT JUNE 30, 2013 (NOTE B)	**$ 169,032**	**$ 373**	**$ 99,171**	**$ 58,997**	**$ 5,223**	**$ 18,587**	**$ 406**	**$ 351,789**

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

Statement of Cash Flows As of June 30, 2013 (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	2013 Combined Total
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net operating revenues	$ 120,728	$ (8)	$ -	$ -	$ (383)	$ 5,897	$ -	$ 126,234
Adjustments to reconcile net operating revenues								
to cash provided by operating activities:								
Depreciation and amortization	124,410	48	-	-	157	6,793	-	131,408
Decommissioning	6,306	-	-	-	-	33	-	6,339
Other	(2,041)	770	-	-	1,458	37	-	224
Change in operating assets and liabilities:								
Deferred charges/costs in excess of billings	(61,332)	(48)	-	-	-	-	-	(61,380)
Accounts receivable	980	11	-	-	(51)	(9)	-	931
Materials and supplies	(10,201)	-	-	-	-	-	-	(10,201)
Prepaid and other assets	(98)	62	-	-	2,572	202		2,738
Due from/to other business units, funds and Participants	14,874	(915)	-	-	-	76	-	14,035
Accounts payable	9,537	58	-	-	95	(96)	-	9,594
Non-operating revenue receipts	112	-	338,733	228,232	-	-	-	567,077
Cash payments for preservation, termination expense	-	-	(534)	(22)	-	-	-	(556)
Cash payments for services	-	-	-	-	-	-	(4,192)	(4,192)
Net cash provided (used) by operating and nonoperating activities	**$ 203,275**	**$ (22)**	**$ 338,199**	**$ 228,210**	**$ 3,848**	**$ 12,933**	**$ (4,192)**	**$ 782,251**

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

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 22 public utility districts and 5 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's 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 1,170-MWe (Design Electric Rating, net) generating plant completed in 1984. Energy Northwest has obtained all permits and licenses required to operate Columbia. 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. A renewal license was granted by the NRC on May 22, 2012 for continued operation of Columbia to December 31, 2043.

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 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, 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, after which FERC will complete the final license renewal documentation for Packwood. Costs incurred to date for relicensing are $3.7 million included in other deferred charges.

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. The participants also share Packwood revenue. (See Note 6).

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.

The Nine Canyon Wind Project (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 Nine Canyon 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 October 30, 2013, 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 Generally Accepted Accounting Principles (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 books of accounts are maintained for each business unit. Payment of the 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 (unaudited) only as each Energy Northwest business unit is financed and accounted for separately from all other current and future business units. The FY 2013 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.

In June 2011, GASB issued Statement No. 63, "Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources and Net Position." Statement No. 63 amends the current net assets reporting requirements by incorporating deferred inflows of resources and deferred outflows of resources into the definitions of required financial statement components and renames "Net Assets" as "Net Position." Statement No. 63 is effective for Energy Northwest beginning in fiscal year 2013. Energy Northwest's financial statements have been modified to conform to the requirements of this statement. Implementation did not have a material impact on the Energy Northwest's financial results.

In March 2012, GASB issued Statement No. 65, "Items, Previously Reported as Assets and Liabilities." Statement No. 65 establishes accounting and financial reporting standards to reclassify certain items previously reported as assets and liabilities as deferred outflows or deferred inflows of resources, or as outflows or inflows of resources. This statement also limits the use of the term deferred in financial statement presentations. This statement is effective for Energy Northwest beginning in fiscal year 2014. The District is currently assessing the financial statement impact of adopting this statement, but does not believe that its impact will be material.

In June 2012, GASB issued Statement No. 68, "Accounting and Financial Reporting for Pensions – An Amendment of GASB Statement No. 27." The primary objective of Statement No. 68 is to improve accounting and financial reporting by state and local governments for pensions. This statement establishes standards for measuring and recognizing liabilities, deferred outflows and deferred inflows of resources and expenses. For defined benefit pension plans, this statement identifies the methods and assumptions to project benefit payments, discount projected benefit payments to their actuarial present value and attribute present value to periods of employee service. Note disclosure and required supplementary information about pensions are also addressed. Statement No. 68 is effective for Energy Northwest beginning in fiscal year 2015. Energy Northwest is currently evaluating the financial statement impact of adopting this statement.

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 (see Note 15).

c) **Capitalized Interest:** 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. If estimated costs are more than inconsequential, an adjustment is made to allocate capitalized interest to the appropriate plant account. Capitalized interest costs were $1.6 million.

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. All expenditures related to the initial purchase of nuclear fuel for Columbia, including interest, were capitalized and carried at cost.

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, unplanned 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 Statements 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 Due To/From other business units. 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) Leases: Consist of separate operating lease agreements. The total of these leases by business unit and their respective amounts paid per year are listed in the table on the next page.

n) Long-Term Liabilities: Consist of obligations related to bonds payable and the associated premiums/discounts and gains/losses. Other noncurrent liabilities for Columbia relates to the dry storage cask activity.

o) 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.

p) 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 net assets are 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.

q) 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 2013 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 funding were projected to cover the total costs of 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 current rate schedule for the Nine Canyon participants covers total estimated project costs occurring in FY 2013 and estimated total cost recovery projections out to the 2030 proposed end date. During FY 2013 there was no cost recovery obtained from REPI.

Projects Operating Lease Costs (Dollars in thousands)

	2014	2015	2016	2017	2018	2019+
Columbia	$ 723	$ 723	$ 723	$ 723	$ 723	$ 18,082
Nuclear Project No. 1	35	35	35	35	35	210
Nine Canyon	684	684	684	684	684	8,209
Business Development Fund	169	169	169	169	169	226
Internal Service Fund	147	147	147	147	147	1,655
Packwood Lake Project	81	81	81	81	81	81
Total	**$ 1,839**	**$ 1,839**	**$ 1,839**	**$ 1,839**	**$ 1,839**	**$ 28,463**

Long-Term Liabilities (Dollars in thousands)

	Balance 6/30/2012	INCREASES	DECREASES	Balance 6/30/2013
Columbia				
Revenue bonds payable	$ 2,441,385	$ 782,655	$ 61,020	$ 3,163,020
Unamortized (discount)/premium on bonds - net	120,221	2,632	17,262	105,591
Unamortized gain/(loss) on bond refundings	(9,966)	3,371	580	(7,175)
Other noncurrent liabilities	15,776	2,142	4	17,914
	$ 2,567,416	**$ 790,800**	**$ 78,866**	**$ 3,279,350**
Nuclear Project No.1				
Revenue bonds payable	$ 1,321,060	$ -	$ 273,055	$ 1,048,005
Unamortized (discount)/premium on bonds - net	56,290	30	20,069	36,251
Unamortized gain/(loss) on bond refundings	(3,614)	3,905	461	(170)
	$ 1,373,736	**$ 3,935**	**$ 293,585**	**$ 1,084,086**
Nuclear Project No.3				
Revenue bonds payable	$ 1,395,405	$ -	$ 166,160	$ 1,229,245
Unamortized (discount)/premium on bonds - net	53,241	8,403	16,689	44,955
Unamortized gain/(loss) on bond refundings	(974)	913	823	(884)
	$ 1,447,672	**$ 9,316**	**$ 183,672**	**$ 1,273,316**
Nine Canyon				
Revenue bonds payable	$ 130,955	$ -	$ 6,835	$ 124,120
Unamortized (discount)/premium on bonds - net	4,743	-	605	4,138
Unamortized gain/(loss) on bond refundings	(279)	88	22	(214)
	$ 135,419	**$ 88**	**$ 7,462**	**$ 128,044**

r) 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 $20.8 million at June 30, 2013 and is recorded as a current liability.

s) 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, 2013 was as follows:

Utility Plant Activity (Dollars in thousands)

	Balance 6/30/2012	Capital Acquisitions	Sale or Other Dispositions	Balance 6/30/2013
Columbia				
Generation	$ 3,791,326	$ 7,482	$ (41)	$ 3,798,767
Decommissioning	14,256	512	-	14,768
Construction Work-in-Progress	60,553	282,452	(226,522)	116,483
Accumulated Depreciation and Decommissioning	(2,441,485)	(81,993)	41	(2,523,438)
Utility Plant, net*	**$ 1,424,650**	**$ 208,453**	**$ (226,522)**	**$ 1,406,581**
Packwood				
Generation	$ 13,625	$ 812	$ -	$ 14,437
Construction Work-in-Progress	-	812	(812)	-
Accumulated Depreciation	(12,764)	(48)	-	(12,812)
Utility Plant, net	**$ 861**	**$ 1,576**	**$ (812)**	**$ 1,625**
Business Development				
General	$ 2,174	$ 369	$ -	$ 2,543
Construction Work-in-Progress	-	369	(369)	-
Accumulated Depreciation	(993)	(157)	-	(1,150)
Utility Plant, net	**$ 1,181**	**$ 581**	**$ (369)**	**$ 1,393**
Nine Canyon				
Generation	$ 133,645	$ 37	$ (32)	$ 133,649
Decommissioning	861	-	-	861
Construction Work-in-Progress	-	37	(37)	-
Accumulated Depreciation and Decommissioning	(47,372)	(6,826)	32	(54,166)
Utility Plant, net	**$ 87,133**	**$ (6,752)**	**$ (37)**	**$ 80,345**
Internal Service Fund				
General	$ 48,410	$ 59	$ (500)	$ 47,969
Construction Work-in-Progress	-	59	(59)	-
Accumulated Depreciation	(36,594)	(2,109)	500	(38,203)
Utility Plant, net	**$ 11,816**	**$ (1,990)**	**$ (59)**	**$ 9,766**

Note 3 –
Available-for-Sale Investments (Dollars in thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia	$ 37,986	$ 14	$ -	$ 38,000
Packwood	1,023	-	-	1,023
Nuclear Project No. 1	213,488	-	-	213,488
Nuclear Project No. 3	149,725	-	-	149,725
Business Development Fund	2,540	-	-	2,540
Internal Service Fund	27,202	5	(4)	27,203
Nine Canyon	13,971	2	(2)	13,971

(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 $1.5 million have a maturity beyond 1 year with the longest maturity being July 5th, 2014.
Of the total $1.5 million maturing beyond 1 year, $1.0 million resides in the Business Development Fund and the remaining $0.5 million resides with Packwood.

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's 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 (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 a multiple financial institution collateral pool administered by the Washington state Treasurer's Local Government Investment Pool (PDPC). 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. All deposits are insured by collateral held in the multiple financial institution collateral pool. State law requires deposits may only be made with institutions that are approved by the PDPC.

Note 4 – Other Charges and Credits for Resources

Other credits of $3.7 million relate to the Packwood relicensing effort. Other credits of $0.1 million for Nine Canyon consist of turbine elevator purchases to be completed in FY 2014.

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), Resolution No.1482 (2006 Bonds), and Resolution No. 1722 (2012 Bonds).

During the year ended June 30, 2013, Energy Northwest issued, for Columbia Series 2012-D and 2012-E fixed rate bonds with a weighted average coupon interest rate ranging from 1.06 percent to 5.0 percent.

The Series 2012-D bonds issued for Columbia are tax-exempt fixed-rate bonds. Series 2012-E bonds issued for Columbia are taxable fixed rate bonds. These bonds were issued in majority to cover fuel purchases (See Note 1).

The Bond Proceeds, Weighted Average Coupon Interest Rates and Bond Proceeds for 2012-D and 2012-E are presented in the following tables:

Bond Proceeds (Dollars in millions)

	2012D	2012E	Total
Columbia	$ 34.14	$ 748.52	$ 782.66
Total	$ 34.14	$ 748.52	$ 782.66

Weighted Average Coupon Interest Rate for New Bonds

	2012D	2012E
Columbia	4.48%	2.50%
Total	4.08%	5.00%

Energy Northwest did not issue or refund any bonds associated with Project No. 1, Project No. 3, Packwood, and Nine Canyon during FY 2013.

Outstanding principal on revenue and refunding bonds for the various business units as of June 30, 2013, and future debt service requirements for these bonds are presented in the following tables:

Columbia Generating Revenue and Refunding Bonds

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
2003A	5.50	7-1-2015	$ 81,090
2003F	5.00-5.25	7-1-13/2018	23,710
2004A	5.25	7-1-17/2018	129,260
2004B	5.50	7-1-2013	12,715
2004C	5.25	7-1-13/2018	15,045
2005A	5.00	7-1-15/2018	114,985
2005C	4.64-4.74	7-1-13/2015	42,885
2006A	5.00	7-1-20/2024	434,210
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	5.10-5.33	7-1-13/2021	10,310
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
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
2012A	5.00	7-1-18/2021	441,240
2012D	5.00	7-1-25/2044	34,140
2012E	1.06-4.14	7-1-15/2037	748,515
		Revenue bonds payable	**$ 3,224,040**
		Estimated fair value at June 30, 2013	**$ 3,512,957** (A)

(A) 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

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1989B	7.125	7-1-2016	$ 41,070
2003A	5.50	7-1-13/2014	174,400
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	7-1-13/2017	103,120
2007A	5.00	7-1-13/2017	51,730
2007B	5.10	7-1-2013	2,290
2007C	5.00	7-1-13/2017	219,020
2008A	5.00-5.25	7-1-13/2017	230,535
2008D	5.00	7-1-13/2017	38,100
2009A	3.25-5.00	7-1-14/2015	48,905
2009B	4.59	7-1-2014	515
2010A	3.00-5.00	7-1-13/2017	54,805
2012A	5.00	7-1-13/2017	155,390
2012B	5.00	7-1-2017	41,285
2012C	1.26	7-1-2015	24,100
		Revenue bonds payable	**$ 1,321,060**
		Estimated fair value at June 30, 2013	**$ 1,425,123** (A)

(A) 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
(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
1989A	(B)	7-1-13/2014	$ 2,815
1989B	(B)	7-1-13/2014	8,297
	7.125	7-1-2016	76,146
Subtotal 1989A and 1989B			87,258
1993C	(A)	7-1-13/2018	23,963
2003A	5.50	7-1-2013	52,890
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
2007C	5.00	7-1-13/2018	55,045
2008A	5.25	7-1-2018	13,790
2008D	5.00	7-1-13/2017	33,595
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
2012A	5.00	7-1-2018	67,885
2012B	3.00-5.00	7-1-16/2017	30,330
2012C	1.26-1.74	7-1-15/2016	61,635
		Compound interest bonds accretion	**111,334**
		Revenue bonds payable	**$ 1,395,405**
		Estimated fair value at June 30, 2013	**$ 1,537,662** (A)

(A) 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.
(B) Compound Interest Bonds

Nine Canyon Wind Project Revenue and Refunding Bonds
(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Amount
2005	4.50-5.00	7-1-13/2023	$ 48,370
2006	4.50-5.00	7-1-13/2030	68,835
2012	2.00-5.00	7-1-13/2023	13,750
		Revenue bond payable	**$ 130,955**
		Estimated fair value at June 30, 2012	**$ 136,617** (A)

(A) 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	**$6,071,460**
Estimated Fair Value at June 30,2013	**$6,612,359**

Debt Service Requirements As of June 30, 2013 (Dollars in thousands)

Columbia Generating Station

Fiscal Year***	Principal	Interest	Total
2013	$ 61,020	$ 71,522	$ 132,542
2014	79,765	140,052	219,817
2015-2017	419,645	382,322	801,967
2018-2022	1,927,765	423,440	2,351,205
2023-2024	648,950	57,484	706,434
2025-2028	54,275	9,799	64,074
2029-2044	32,620	12,972	45,592
	$ 3,224,040	**$ 1,097,591**	**$ 4,321,631**

* Principal and Interest due July 1, 2013.
*** Fiscal year for this report indicates when the obligations are expected to be paid.

Nuclear Project No. 1

Fiscal Year***	Principal	Interest	Total
2013	$ 273,055	$ 33,186	$ 306,241
2014	332,100	52,401	384,501
2015	191,430	35,443	226,873
2016	239,385	27,026	266,411
2017	285,090	14,117	299,207
	$ 1,321,060	**$ 162,174**	**$ 1,483,234**

* Principal and Interest due July 1, 2013.
*** Fiscal year for this report indicates when the obligations are expected to be paid.

Nuclear Project No. 3

Fiscal Year***	Principal	Interest	Total
2013	$ 131,875	$ 65,552	$ 197,427
2014	124,704	88,738	213,442
2015	129,795	60,487	190,283
2016	247,499	56,838	304,337
2017	177,617	45,124	222,741
2018	472,581	32,625	505,206
Adjustment **	**111,334**	**(111,334)**	-
	$ 1,395,405	**$ 238,031**	**$ 1,633,435**

* Principal and Interest due July 1, 2013.
** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet.
*** Fiscal year for this report indicates when the obligations are expected to be paid.

Nine Canyon Wind Project

Fiscal Year***	Principal	Interest	Total
2013	$ 6,835	$ 3,062	$ 9,897
2014-2017	31,135	21,438	52,573
2018-2021	37,415	15,251	52,666
2022-2025	30,175	7,805	37,980
2026-2029	19,855	3,305	23,160
2030	5,540	249	5,789
	$ 130,955	**$ 51,109**	**$ 182,064**

* Principal and Interest due July 1, 2013.
*** Fiscal year for this report indicates when the obligations are expected to be paid.

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 previously 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

Power produced by Packwood is provided to the 12 member utilities. The member utilities pay the annual costs, including any debt service, of Packwood and are obligated to pay these annual costs whether or not Packwood is operational. 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 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, Wash., 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

The Legislature established PERS in 1947. Membership in the system includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts; employees of legislative committees; community and technical colleges, college and university employees not participating in higher education retirement programs; employees of district and municipal courts; and employees of local governments. Approximately 50 percent of PERS salaries are accounted for by state employment. PERS retirement benefit provisions are established in chapters 41.34 and 41.40 RCW and may be amended only by the State Legislature.

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.

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 exercised 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 Plan 3. The option must be exercised within 90 days of employment. Employees who fail to choose within 90 days default to 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 is comprised of and reported as three separate plans for accounting purposes: Plan 1, Plan 2/3, and Plan 3. Plan 1 accounts for the defined benefits of Plan 1 members. Plan 2/3 accounts for the defined benefits of Plan 2 members and the defined benefit portion of benefits for Plan 3 members. Plan 3 accounts for the defined contribution portion of benefits for Plan 3 members. Although members can only be a member of either Plan 2 or Plan 3, the defined benefit portions of Plan 2 and Plan 3 are accounted for in the same pension trust fund. All assets of this Plan 2/3 defined benefit plan may legally be used to pay the defined benefits of any of the Plan 2 or Plan 3 members or beneficiaries, as defined by the terms of the plan. Therefore, Plan 2/3 is considered to be a single plan for accounting purposes.

PERS Plan 1 and Plan 2 retirement benefits are financed from a combination of investment earnings and employer and employee contributions. Employee contributions to the PERS Plan 1 and Plan 2 defined benefit plans accrue interest at a rate specified by the Director of DRS. During DRS' fiscal year 2012, the rate was five and one-half percent compounded quarterly. Members in PERS Plan 1 and Plan 2 can elect to withdraw total employee contributions and interest thereon upon separation from PERS-covered employment.

PERS Plan 1 members are vested after the completion of five years of eligible service.

PERS 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, but the benefit may not exceed 60 percent of the AFC. The AFC is the monthly average of the 24 consecutive highest-paid service credit months.

The monthly benefit is subject to a minimum for 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. If a survivor option is chosen, the benefit is reduced. Plan 1 members retiring from inactive status prior to the age of 65 may also receive actuarially reduced benefits. Plan 1 members may elect to receive an optional Cost of Living Adjustment (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 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. The AFC is the monthly average of the 60 consecutive highest-paid service months. 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.

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 3 has a dual benefit structure. Employer contributions finance a defined benefit component and member contributions finance a defined contribution component. As established by chapter 41.34 RCW, employee contribution rates to the defined contribution component range from 5 to 15 percent of salaries, based on member choice. There are currently no requirements for employer contributions to the defined contribution component of PERS Plan 3.

PERS Plan 3 defined contribution retirement benefits are dependent upon the results of investment activities. Members may elect to self-direct the investment of their contributions. Any expenses incurred in conjunction with self-directed investments are paid by members. Absent a member's self-direction, PERS Plan 3 investments are made in the same portfolio as that of the PERS 2/3 defined benefit plan.

There are 1,184 participating employers in PERS. Membership in PERS consisted of the following as of the latest actuarial valuation date for the plans of June 30, 2011:

Retirees and Beneficiaries Receiving Benefits	79,363
Terminated Plan Members Entitled to But Not Yet Receiving Benefits	29,925
Active Plan Members Vested	105,578
Active Plan Members Non-vested	46,839
Total	**261,705**

Funding Policy

Each biennium, the state Pension Funding Council adopts PERS Plan 1 employer contribution rates, PERS Plan 2 employer and employee contribution rates, and PERS 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. Under PERS Plan 3, employer contributions finance the defined benefit portion of the plan and member contributions finance the defined contribution portion. The Plan 3 employee contribution rates range from 5 to 15 percent, based on member choice. 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, 2012, are as follows:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	7.25%**	7.25%**	7.25%***
Employee	6.00%****	4.64%****	*****

* The employer rates include the employer administrative expense fee currently set at 0.16 percent.

** The employer rate for state elected officials is 10.74 percent for Plan 1 and 7.21 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 4.64 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
2013	$ 106,514	$ 10,630,935	$ 5,075,823
2012	$ 124,071	$ 9,773,209	$ 4,710,819
2011	$ 184,863	$ 7,921,762	$ 4,281,077

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 2013 Energy Northwest contributed $3.1 million in employer matching funds while employees contributed $10.8 million for FY 2013.

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 62 retirees who 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 2013 and was $2.82 per $1,000 of coverage. Employees who retired prior to January 1, 1995, contribute 58 cents 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, 2013, was $0.6 million for these benefits.

During FY 2013, 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 2013 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 - Nuclear Licensing and Insurance

Nuclear Licensing

Energy Northwest is a licensee of the Nuclear Regulatory Commission and is subject to routine licensing and user fees. Additionally, Energy Northwest may be subject to license modification, suspension, revocation, or civil penalties in the event regulatory or license requirements are violated.

Nuclear Insurance

Nuclear insurance includes liability coverage, property damage, decontamination and premature decommissioning coverage and accidental outage and/or extra expense coverage. The liability coverage is governed by the Price-Anderson Act (Act), while the property damage, decontamination and premature decommissioning coverage are defined by the Code of Federal Regulations. Energy Northwest continues to maintain all regulatory required limits as defined by the NRC, Code of Federal Regulations and the Act. The NRC requires Energy Northwest to certify nuclear insurance limits on an annual basis. Energy Northwest intends to maintain insurance against nuclear risks to the extent such insurance is available on reasonable terms and in an amount and form consistent with customary practice. Energy Northwest is self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Such losses could have an effect on Energy Northwest's results of operations and cash flows. All dollar figures noted below are as of June 30, 2013.

American Nuclear Insurance (ANI) Coverage: The Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $12.6 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection (SFP). Energy Northwest has $375 million of liability insurance as the first layer of protection. If any US nuclear generation plant has a significant event which exceeds the plant's first layer of protection, every operating licensed reactor in the US is subject to an assessment up to $117.5 million not including state insurance premium tax. Assessments are limited to $ 17.5 million per reactor, per year, per incident, excluding tax. The SFP is adjusted at least every 5 years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

NEIL Coverage: The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1.06 billion nuclear decontamination and property damage insurance and requires the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Energy Northwest has aggregate coverage in the amount of $2.25 billion which is subject to a $5 million deductible per accident.

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 net assets are 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).

As of June 30, 2013, Columbia has a capital decommissioning net asset value of zero and an accumulated liability of $124.9 million for the generating plant, and for the ISFSI a net asset value of $1.1 million and an accumulated liability of $2.2 million. The adjustment to ISFSI was associated with new Nuclear Regulatory Commission (NRC) spent fuel decommissioning requirements.

Nuclear Project No. 1 in FY 2013 current year accretion of $.5 million and upward revision in future restoration estimates of $1.3 million resulted in the increase to the ARO liability of $1.8 million. Nuclear Project No. 1 has a capital decommissioning net asset value of zero and an accumulated liability of $18.2 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, 2013, Nine Canyon has a capital decommissioning net asset value of $0.6 million and an accumulated liability of $1.3 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, 2013. The balance is included in the accounts payable and accrued expense balances for each unit. ISFSI is included in Columbia's balance:

Asset Retirement Obligation (Dollars in millions)

Columbia Generating Station		
Balance At June 30, 2012	$	118.70
Current year accretion expense		6.21
ARO at June 30, 2013	**$**	**124.91**
ISFSI		
Balance At June 30, 2012	$	1.57
Current year accretion expense		0.08
Revision in future estimates		0.51
ARO at June 30, 2013	**$**	**2.16**
Nuclear Project No. 1		
Balance At June 30, 2012	$	16.40
Current year accretion expense		0.50
Revision in future restoration estimates		1.34
ARO at June 30, 2013	**$**	**18.24**
Nine Canyon Wind Project		
Balance At June 30, 2012	$	1.24
Current year accretion expense		0.05
ARO at June 30, 2013	**$**	**1.29**

Note 12 - Decommissioning and Site Restoration

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on providing financial assurance for decommissioning 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 March 31, 1999, and reports are required every two years thereafter. Energy Northwest submitted its most recent report to the NRC in March 2013.

Energy Northwest's current estimate of Columbia's decommissioning costs in FY 2013 dollars is $459.0 million (Columbia - $454.6 million and ISFSI - $4.4 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 $109.0 million in constant dollars (based on the 2013 study) and is updated biannually along with the decommissioning estimate. Both decommissioning and site restoration estimates (based on 2013 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, 2013, totaled approximately $188.6 million and $31.3 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, 2013, is $1.1 million. These contributions will occur through FY 2044; cash payments will begin for decommissioning and site restoration in FY 2045 with equal installments for five years totaling $10.6 million in constant dollars based on the 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 no viable alternative use has been found to-date. 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. In 1995, a group from Grays Harbor County, Wash., 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 are governed by site certification agreements between Energy Northwest and the state of Washington and regulations adopted by EFSEC, and a lease agreement with DOE. Energy Northwest submitted a site restoration plan 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 $12.4 million in network revenue bonds and note payables outstanding, based on their December 30, 2012 audited 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 $1.1 million. 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 2013 the Business Development Fund was not required to contribute to NoaNet. Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, NoaNet Headquarters, 5802 Overlook Ave. NE, Tacoma, Wash., 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 vs. United States of America filed in U.S. Court of Federal Claims in July 2011 (Cause No. 11-447C-EJD). This is the second action for partial breach of contract brought by Energy Northwest against the United States (Department of Energy, "DOE") for damages ranging between September 1, 2006 through July 2012, 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. After extensive discovery, Energy Northwest is claiming total damages of approximately $24.9 million in this case. Energy Northwest believes DOE does not have a defense on liability, which was established in the prior case.

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.

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 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 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 settled in June 2013. 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. The total dollars recorded in FY 2013 were $148,000.

Note 15 – Nuclear Fuels

In May 2012, Energy Northwest entered into agreements with three other parties for processing high assay uranium tails. The Program consists of several agreements between the parties involved, entered into as a joint effort between the Department of Energy (DOE), Tennessee Valley Authority (TVA), United States Enrichment Corporation (USEC) and Energy Northwest to enrich approximately 9,082 metric tons (MTU) of Depleted Uranium Hexafluoride (DUF6) with an average assay of 0.44 weight percent U235 (wt%) that will yield approximately 482 MTU of enriched uranium product (EUP) with an average assay of 4.4 wt%.

DOE and Energy Northwest have entered into an agreement for the transfer of the DUF6 to Energy Northwest. The agreement addresses delivery and transfer of title of the DUF6, return of residual DUF6 after enrichment, storage of the EUP, and payment of DOE's costs. The costs for the handling of the DUF6 and storage of the EUP are anticipated to be $5 million or less. As of June 30, 2013, Energy Northwest had recorded $0.4 million in charges to the DOE for delivery of the DUF6, which is capitalized as cost of the fuel being purchased.

Under the Depleted Uranium Enrichment Program (DUEP), Energy Northwest purchased from USEC all of the Separative Work Units (SWU) contained in the EUP. Upon finalization of the program, Energy Northwest had purchased a total of 481.6 MTU of EUP from USEC at a cost of $687.5 million, which is recorded in nuclear fuel, net of accumulated amortization, as of June 30, 2013.

Energy Northwest and TVA have entered into an agreement for the sale and purchase of a portion of the SWU and Feed Component of the EUP. The sales under the agreement are expected to total approximately $731 million. The sales under this agreement are scheduled to take place between 2015 and 2022.

Energy Northwest has a contract with DOE that requires DOE to accept title and dispose of spent nuclear fuel. 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.

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. The amount moved to spent fuel for cooling increased $55.3 million. Fees for disposal of fuel in the reactor are expensed as part of the fuel cost.

The current period operating expense for Columbia includes an $8.1 million charge from DOE for future spent fuel storage and disposal in accordance with the Nuclear Waste Policy Act of 1982 and $40.3 million for amortization of fuel used in the reactor.

Energy Northwest has completed the Independent Spent Fuel Storage Installation (ISFSI) project, which is a temporary dry cask storage facility to be used until 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 2013. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refueling. Current period costs were $2.1 million for dry cask storage costs which are recorded in nuclear fuel expense.

Designer: **Ben Stewart**
Editor: **Angela Walz**

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL
FOR THE SERIES 2014-C BONDS

Energy Northwest

J.P. Morgan Securities LLC

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

Merrill Lynch, Pierce, Fenner & Smith Incorporated

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$197,110,000/$72,305,000] Project [1/3] Electric Revenue Refunding Bonds, Series 2014-C (the "2014-C Bonds"). The 2014-C Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on November 23, 1993, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on July 24, 2014 (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 2014-C Bonds are subject to redemption prior to their stated maturities as provided in the Bond Resolutions. The 2014-C Bonds rank junior as to security and payment to bonds issued and outstanding under the Project [1/3] Prior Lien Resolution. The 2014-C 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 2014-C Bonds and apply the proceeds of the 2014-C Bonds in accordance with the Supplemental Resolution.

2. The Bond Resolutions have been duly and lawfully adopted by Energy Northwest, are in full force and effect, are valid and binding upon Energy Northwest and are enforceable in accordance with their terms. Energy Northwest's covenants in the Prior Lien Resolution to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the Prior Lien Bonds prior to paying the principal of and interest on the 2014-C Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2014-C 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 2014-C Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2014-C 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 2014-C Bonds may be limited by laws relating to bankruptcy, reorganization, insolvency, moratorium or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and the exercise of judicial discretion, and we express no opinion regarding the enforceability of provisions in the Bond Resolutions that provide for rights of indemnification.

This opinion is given as of the date hereof, and we assume no obligation to update, revise or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

Very truly yours,

FOSTER PEPPER PLLC

PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL
FOR THE SERIES 2014-C BONDS

Energy Northwest

J.P. Morgan Securities LLC

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

Merrill Lynch, Pierce, Fenner & Smith Incorporated

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$197,110,000/$72,305,000] Project [1/3] Electric Revenue Refunding Bonds, Series 2014-C (the "2014-C Bonds"). The 2014-C Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on November 23, 1993, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on July 24, 2014 (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 2014-C Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement"), (collectively the "Agreements") by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State and such statutes and regulations as we deemed relevant to this opinion, including particularly the Act;

(b) The Constitution of the United States of America and such statutes and regulations as we deemed relevant to this opinion, including particularly the Bonneville Project Act of 1937, as amended (the "Bonneville Act"), the Flood Control Act of 1944, Public Law 88-552, as amended, the Federal Columbia River Transmission System Act of 1974, as amended, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, as amended;

(c) Certified copies of the Electric Revenue Bond Resolution and the Supplemental Resolution;

(d) Certified copies of the Net Billing Agreements and the Assignment Agreement;

(e) The Certificate of the General Counsel 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) A certified copy of Energy Northwest Resolution No. [769/775] as amended and supplemented (the "Prior Lien Resolution"); and

(k) Such other documents, agreements, proceedings, pleadings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon and based on the assumptions, exceptions and conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Project [1/3] consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville 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 General Counsel of Energy Northwest 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 2014-C BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$197,110,000 Project 1 Electric Revenue Refunding Bonds, Series 2014-C
$72,305,000 Project 3 Electric Revenue Refunding Bonds, Series 2014-C

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $197,110,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 1 2014-C Bonds"), and $72,305,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2014-C (the "Project 3 2014-C Bonds," and together with the Project 1 2014-C Bonds, the "Series 2014-C Bonds").

The Project 1 2014-C Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), and Resolution No. 835, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on July 24, 2014 (the "Project 1 Resolution"). The Project 1 Resolution provides that the Project 1 2014-C Bonds are being issued for the purpose of repaying the principal portion of a bond anticipation note which evidences an advance made by JP Morgan Chase Bank, National Association (the "Bank") to Energy Northwest pursuant to a Loan Agreement dated June 19, 2014 (the "Loan Agreement"). That advance was used to pay a portion or all principal on certain outstanding Project 1 Electric Revenue Bonds that matured on July 1, 2014.

The Project 3 2014-C Bonds are being issued pursuant to the Act and Resolution No. 838, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on February 27, 2014 (the "Project 3 Resolution," and together with the Project 1 Resolution, the "Resolutions"). The Project 3 Resolution provides that the Project 3 2014-C Bonds are being issued for the purpose of repaying the principal portion of a bond anticipation note which evidences an advance made by the Bank to Energy Northwest pursuant to the Loan Agreement. That advance was used to pay a portion or all principal on certain outstanding Project 3 Electric Revenue Bonds that matured on July 1, 2014.

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 2014-C Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, 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 2014-C Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2014-C Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated August 5, 2014 relating to the Series 2014-C Bonds, or other offering material relating to the Series 2014-C 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 2014-C Bonds and with respect to the due authorization and issuance of the Series 2014-C 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 2014-C Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended, and Section 103 of the Internal Revenue Code of 1954, as amended.

2. Interest on the Series 2014-C 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 2014-C Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

We express no opinion regarding other tax consequences relating to the ownership or disposition of, or the amount, accrual or receipt of interest on, the Series 2014-C Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2014 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 2014 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 Resolutions authorizing the Series 2014-C Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2014-C 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 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, 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, Columbia or Project 3 Prior Lien Bonds remain outstanding, except for the lien and pledge of the Prior Lien Resolutions, and all corporate action on the part of Energy Northwest to that end has been duly and validly taken. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

Subject to the provisions of the Prior Lien Resolutions, Energy Northwest will not hereafter create any other special fund or funds for the payment of bonds, warrants or other obligations or issue any bonds, warrants or other obligations payable out of or secured by a pledge of revenues or create any additional obligations which will rank on a parity with or in priority over the pledge and lien of such revenues created under the Electric Revenue Bond Resolutions, except that Energy Northwest may issue bonds, notes or other obligations, under a separate resolution or resolutions, which are payable from or secured by a pledge of the revenues and may create or cause to be created any lien or charge on such revenues, ranking on a parity with the pledge and lien created by the Electric Revenue Bond Resolutions, for any one or more of the purposes provided in the Electric Revenue Bond Resolutions or may create Parity Reimbursement Obligations. However, Energy Northwest shall not issue any such additional bonds, notes or other obligations or create Parity Reimbursement Obligations unless, on the date of issue of such bonds, the certain contracts or agreements described in the Electric Revenue Bond Resolutions are in full force and effect and no Event of Default under the Electric Revenue Bond Resolutions shall have occurred and be continuing.

Further Assurances. Energy Northwest will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights, revenues and other funds pledged or assigned to the payment of the obligations issued by Energy Northwest payable from the revenues of each Project, including the Electric Revenue Bonds or intended so to be, or which Energy Northwest may hereafter become bound to pledge or assign.

Tax Covenants. Energy Northwest covenants with the owners from time to time of the Electric Revenue Bonds that (i) throughout the term of the Electric Revenue Bonds, and (ii) through the date that the final rebate, if any, must be made to the United States in accordance with Section 148 of the Code it will comply with the provisions of Sections 103 and 141 through 150 of the Code and all regulations proposed and promulgated thereunder that must be satisfied in order that interest on the Electric Revenue Bonds shall be and continue to be excluded from gross income for federal income tax purposes.

Energy Northwest shall not permit at any time or times any of the proceeds of the Electric Revenue Bonds or any other funds of Energy Northwest to be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Electric Revenue Bond to be an "arbitrage bond" as defined in Section 148 of the Code, or any successor provision of law.

Energy Northwest shall not permit at any time or times any proceeds of any Series of Electric Revenue Bonds or any other funds of Energy Northwest to be used, directly or indirectly, in a manner which would result in the exclusion of any Electric Revenue Bond from the treatment afforded by Section 103(a) of the Code.

Anything contained in the three preceding paragraphs to the contrary notwithstanding, Energy Northwest reserves the right to issue, from time to time, one or more Series of Electric Revenue Bonds the interest on which is includable in the gross income of the recipient thereof for federal income tax purposes ("Taxable Bonds"), provided that the issuance of any such Series of Taxable Bonds does not adversely affect the federal tax exemption of the interest on any other Series of Electric Revenue Bonds.

Events of Default and Remedies (Section 801)

The occurrence of one or more of the following events shall constitute an "Event of Default" under the Electric Revenue Bond Resolution to which such Event of Default relates:

(1) if payment of principal or the redemption price of any related Electric Revenue Bond shall not punctually be made when due and payable, whether at the stated maturity thereof, upon redemption or otherwise;

(2) if payment of the interest on any related Electric Revenue Bond shall not punctually be made when due;

(3) if payment of any related Parity Reimbursement Obligation shall not be punctually made when due;

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed (other than the covenant relating to compliance with the respective Prior Lien Resolutions), and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected; and provided further that the exclusion of the covenant relating to compliance with the respective Prior Lien Resolutions, shall not be construed to prevent the Trustee from enforcing any remedy it may have, at law or in equity, for a breach of such covenant;

(5) if an order, judgment, or decree shall be entered by any court of competent jurisdiction, with the consent or acquiescence of Energy Northwest, or if such order, judgment or decree, having been entered without the consent or acquiescence of Energy Northwest, shall not be vacated or set aside or discharged or stayed (or in case custody or control is assumed by said order, such custody or control shall not otherwise be terminated) within ninety (90) days after the entry thereof, and if appealed, shall not thereafter be vacated or discharged: (i) appointing a receiver, trustee or liquidator for Energy Northwest; or (ii) assuming custody or control of the whole or any substantial part of the applicable Project under the provisions of any law for the relief or aid of debtors; or (iii) approving a petition filed against Energy Northwest under the provisions of 11 USC 901-946, as amended (the "Bankruptcy Act");

or (iv) granting relief to Energy Northwest under any amendment to said Bankruptcy Act, or under any other applicable Bankruptcy Act, which shall give relief substantially similar to that afforded by Chapter IX thereof; and

(6) if Energy Northwest shall (i) admit in writing its inability to pay its debts generally as they become due; or (ii) file a petition in bankruptcy or seeking a composition of indebtedness; or (iii) make an assignment for the benefit of its creditors; or (iv) file a petition or any answer seeking relief under the Bankruptcy Act referred to in the preceding clause, or under any amendment thereto, or under any other applicable bankruptcy act which shall give relief substantially the same as that afforded by Chapter IX of said act; or (v) consent to the appointment of a receiver of the whole or any substantial part of the applicable Project; or (vi) consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of Energy Northwest or of the whole or any substantial part of the applicable Project.

Upon the occurrence of an Event of Default described in the preceding paragraphs, and in each and every such case, so long as such Event of Default shall not have been remedied, unless the principal of all the related Electric Revenue Bonds shall have already become due and payable, the Trustee may, and upon the written request of the owners of not less than 25% of all related Electric Revenue Bonds then outstanding shall, proceed to enforce by such proceedings at law or in equity as it deems most effectual the rights of related Bondholders, and either the Trustee (by notice in writing to Energy Northwest), or the owners of not less than 25% in principal amount of the related Electric Revenue Bonds outstanding (by notice in writing to Energy Northwest and the Trustee), may declare the principal of all the related Electric Revenue Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable; provided, however, that so long as any of the Prior Lien Bonds of the related Project remain outstanding, no such declaration may be made unless the principal of all the Prior Lien Bonds of the related Project then outstanding, and the interest accrued thereon, shall have been declared to be due and payable immediately pursuant to Section 12.1 of Resolution No. 769, Section 11.1 of Resolution No. 640 or Section 11.1 of Resolution No. 775, as the case may be. The Trustee shall not be obligated to notify Energy Northwest of its intent to make such a declaration prior to making such declaration. The right of the Trustee or of the owners of not less than 25% in principal amount of the related Electric Revenue Bonds to make any such declaration, however, shall be subject to the condition that if, at any time after such declaration, but before the related Electric Revenue Bonds shall have matured by their terms, all overdue installments of interest upon the related Electric Revenue Bonds, together with interest on such overdue installments of interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee (including reasonable fees and expenses of counsel to the Trustee), and all other sums then payable by Energy Northwest under the related Electric Revenue Bond Resolution (except the principal of, and interest accrued since the next preceding Payment Date on, the related Electric Revenue Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the related Electric Revenue Bonds or under the related Electric Revenue Bond Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be cured or provision shall be made therefor, then and in every such case the owners of a majority in principal amount of the related Electric Revenue Bonds outstanding, by written notice to Energy Northwest and to the Trustee, may rescind such declaration and annul such default in its entirety, or, if the Trustee shall have acted itself, and if there shall not have been theretofore delivered to the Trustee written directions to the contrary by the owners of a majority in principal amount of the related Electric Revenue Bonds then outstanding, then any such declaration shall *ipso facto* be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any resulting right or power.

Notice to Bondholders of an Event of Default (Section 802)

The Trustee, within 25 days after the occurrence of an Event of Default, shall give to the Bondholders of the related Electric Revenue Bonds, in the manner provided in the applicable Electric Revenue Bond Resolution, notice of all defaults known to the Trustee, and shall give prompt written notice thereof to Energy Northwest, unless such defaults shall have been cured before the giving of such notice.

Accounting and Examination of Records After Default (Section 803)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and account of Energy Northwest relating to the related Project and all other records relating thereto shall at all times be subject to the inspection and use of the Trustee and any persons holding at least 25% of the principal amount of the related Electric Revenue Bonds outstanding and of their respective agents and attorneys or of any committee therefor.

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, Energy Northwest will continue to account, as a trustee of an express trust, for all revenues and other moneys, securities and funds pledged under the related Electric Revenue Bond Resolution.

Application of Revenues in an Event of Default (Section 804)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee (i) forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution, and (ii) subject to the provisions of the respective Prior Lien Resolutions as promptly as practicable after receipt thereof, all revenues of the related Project (provided that if other Parity Debt is outstanding Energy Northwest shall pay over to the Trustee the Trustee's pro rata share of such revenues).

Subject to the provisions of the Prior Lien Resolutions, respectively, during the continuance of an Event of Default, the revenues and other moneys of the related Project received by the Trustee shall be applied by the Trustee: first, to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the related Project, including the costs of decommissioning and site restoration, if any, and all other proper disbursements or liabilities made or incurred by the Trustee (including the fees and expenses of counsel to the Trustee); and second, to the then due and overdue payments into the related Debt Service Fund and the due and overdue payments on any related Parity Reimbursement Obligations and the due and overdue payments of any other obligation of Energy Northwest for which the Revenues are pledged on a parity with the pledge under Section 202(a) of the related Electric Revenue Bond Resolution pursuant to a Supplemental Electric Revenue Bond Resolution ("Other Parity Obligations"); and lastly, for any lawful purpose in connection with the related Project.

In the event that at any time the funds held by the Trustee shall be insufficient for the payment of the principal of, premium, if any, and interest then due on the related Electric Revenue Bonds and payments then due on any related Parity Reimbursement Obligations and Other Parity Obligations, such funds (other than funds held for the payment or redemption of particular Electric Revenue Bonds or Parity Reimbursement Obligations or Other Parity Obligations, including, without limiting the generality of the foregoing, amounts held in any Reserve Account for a particular Series of Electric Revenue Bonds) and all revenues of Energy Northwest and other moneys received or collected for the benefit or for the account of owners of the Electric Revenue Bonds and any Parity Reimbursement Obligations and Other Parity Obligations by the Trustee shall be applied as follows:

(1) Unless the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the applicable Project and all other proper disbursements or liabilities made or incurred by the Trustee;

Second, to the payment to the persons entitled thereto of all installments of interest then due on the related Electric Revenue Bonds (including any interest on overdue principal) in the order of the maturity of such installments, earliest maturities first, and on any related Parity Reimbursement Obligations and Other Parity Obligations and if the amounts available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Third, to the payment to the persons entitled thereto of the principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at the time of such payment without preference or priority of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, and if the amounts available therefor shall not be sufficient to pay in full any principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at such time, then to the payment thereof, ratably, according to the amounts due respectively for principal and redemption premium, without any discrimination or preference.

(2) If the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the related Project and all other proper disbursements or liabilities made or incurred by the Trustee; and

Second, to the payment of the principal and interest then due and unpaid upon the related Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Whenever moneys are to be applied as described in the preceding paragraphs, such moneys shall be applied by the Trustee, at such times, and from time to time, as it in its sole discretion shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future.

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the

Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its money, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

Remedies Not Exclusive (Section 809)

No remedy by the terms of either of the Electric Revenue Bond Resolutions conferred upon or reserved to the owners of the related Electric Revenue Bonds is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to any other remedy given to the owners of the related Electric Revenue Bonds or now or hereafter existing at law or in equity or by statute.

Waivers of Default (Section 810)

No delay or omission of any owner of Electric Revenue Bonds to exercise any right or power arising upon the occurrence of a default hereunder, including an Event of Default, will impair any right or power or shall be construed to be a waiver of any such default or to be an acquiescence therein. Every power and remedy given by this Article to the Trustee or to the owners of Electric Revenue Bonds may be exercised from time to time and as often as may be deemed expedient by such Trustee or by such owners.

Prior to the declaration of acceleration of the Electric Revenue Bonds as provided in Section 801, the holders of a majority in principal amount of the Electric Revenue Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the holders of all the Electric Revenue Bonds waive any past default under this Resolution and its consequences, except a default described in paragraph (1), (2), (3), or (4) of Section 801. No such waiver will extend to any subsequent or other default or impair any right consequent thereon.

Supplemental Electric Revenue Bond Resolutions (Article IX)

Supplemental Electric Revenue Bond Resolutions Effective Without Consent of Owners of Electric Revenue Bonds. Energy Northwest, from time to time and at any time and without the consent or concurrence of any owner of any Electric Revenue Bond, may adopt a resolution amendatory of each Electric Revenue Bond Resolution or supplemental to each Electric Revenue Bond Resolution (i) for the purpose of providing for the issuance of Electric Revenue Bonds pursuant to the provisions of Article II of each Electric Revenue Bond Resolution, or (ii) if the provisions of such Supplemental Electric Revenue Bond Resolutions shall not adversely affect the rights of the owners of the Electric Revenue Bonds of each Series or, if a Series consists of two or more subseries, of each subseries thereof, affected by such Supplemental Electric Revenue Bond Resolutions then outstanding, for any one or more of the following purposes:

(1) to make any changes or corrections in the Electric Revenue Bond Resolutions as to which Energy Northwest shall have been advised by counsel that the same are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provision or omission or mistake or manifest error contained in the Electric Revenue Bond Resolutions, or to insert in the Electric Revenue Bond Resolutions such provisions clarifying matters or questions arising under the Electric Revenue Bond Resolutions as are necessary or desirable;

(2) to add additional covenants and agreements of Energy Northwest for the purpose of further securing the payment of the Electric Revenue Bonds;

(3) to surrender any right, power or privilege reserved to or conferred upon Energy Northwest by the terms of the Electric Revenue Bond Resolutions;

(4) to confirm as further assurance any lien, pledge or charge, or the subjection to any lien, pledge, or charge, created or to be created by the provisions of the Electric Revenue Bond Resolutions;

(5) to grant or to confer upon the owners of the Electric Revenue Bonds any additional rights, remedies, powers, authority or security that lawfully may be granted to or conferred upon them, or to grant to or to confer upon the Trustee for the benefit of the owners of the Electric Revenue Bonds any additional rights, duties, remedies, powers, authority or security or to provide for one or more Credit Facilities;

(6) to make any appointment or to add any provision, in either case, required or permitted by the Electric Revenue Bond Resolutions to be so made or added pursuant to a Supplemental Electric Revenue Bond Resolution;

(7) to enter into Payment Agreements; and

(8) to make any other change which Energy Northwest deems necessary or desirable and which does not adversely affect the rights of the Bondholders.

Supplemental Electric Revenue Bond Resolutions Effective With Consent of Bondholders. At any time, Supplemental Electric Revenue Bond Resolutions may be adopted subject to consent by Bondholders in accordance with and subject to the provisions of each Electric Revenue Bond Resolution, which Supplemental Electric Revenue Bond Resolutions, upon the filing with the Trustee of a copy thereof certified by an authorized officer of Energy Northwest and upon compliance with the provisions of Article X of each Electric Revenue Bond Resolution, shall become fully effective in accordance with its terms as provided in said Article.

Powers of Amendment (Section 1002)

Any modification or amendment of the Electric Revenue Bond Resolutions or of the rights and obligations of Energy Northwest and of the owner of the Electric Revenue Bonds thereunder, in any particular, may be made by Supplemental Electric Revenue Bond Resolutions, with the written consent given as provided in each Electric Revenue Bond Resolution, (i) of the owners of not less than a majority in principal amount of the related Electric Revenue Bonds outstanding at the time such consent is given, and (ii) in case less than all of the several Series of Electric Revenue Bonds or, if any Series consists of two or more subseries, the subseries thereof, then outstanding are affected by the modification or amendment, of the owners of not less than a majority in principal amount of the Electric Revenue Bonds of such Series or subseries, as the case may be, so affected and outstanding at the time such consent is given; except that if such modification or amendment will, by its terms, not take effect so long as any Electric Revenue Bonds of any specified like Series, subseries, if applicable, and maturity remain outstanding, the consent of the owners of such Electric Revenue Bonds shall not be required and such Electric Revenue Bonds shall not be deemed to be outstanding for the purpose of any calculation of outstanding Electric Revenue Bonds under this provision of each Electric Revenue Bond Resolution. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any outstanding Electric Revenue Bond or of any installment of interest thereon or a reduction in the principal amount or the redemption price thereof or in the rate of interest thereon without the consent of the owner of such Electric Revenue Bond, or shall reduce the percentages or otherwise affect the classes of Electric Revenue Bonds the consent of the owners of which is required to effect any such modification or amendment, or permit a preference or priority of any Electric Revenue Bond over any other or shall change or modify any of the rights or obligations of any fiduciary without its written assent thereto. For the purposes of this provision of each Electric Revenue Bond Resolution, a Series or subseries, as the case may be, shall be deemed to be affected by a modification or amendment of each Electric Revenue Bond Resolution if the same adversely affects or diminishes the rights of the owners of Electric Revenue Bonds of such Series or subseries, respectively. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment of the Electric Revenue Bonds of any particular Series, Subseries, if applicable, or maturity would be affected by any modification or amendment of the Electric Revenue Bond Resolutions and any such determination shall be binding and conclusive on Energy Northwest and all owners of Electric Revenue Bonds. For the purposes of this Section, the owners of the Electric Revenue Bonds may include the initial owners thereof, regardless of whether such Electric Revenue Bonds are being held for immediate resale.

Defeasance (Article XI)

Except as otherwise provided in each Supplemental Electric Revenue Bond Resolution authorizing the issuance of variable rate Electric Revenue Bonds, the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in such Electric Revenue Bond Resolutions, shall be fully discharged and satisfied as to any related Electric Revenue Bond and such related Electric Revenue Bond shall no longer be deemed to be outstanding hereunder,

(i) when such related Electric Revenue Bond shall have been canceled, or shall have been surrendered for cancellation or is subject to cancellation, or shall have been purchased by the Trustee from moneys held under the related Electric Revenue Bond Resolutions; or

(ii) as to any related Electric Revenue Bond not canceled or surrendered for cancellation or subject to cancellation or so purchased, when payment of the principal of and premium, if any, on such related Electric Revenue Bond, plus interest on such principal to the due date thereof (whether such due date be by reason of maturity or upon redemption or prepayment, or otherwise) either (A) shall have been made or caused to be made in accordance with the terms thereof, or (B) shall have been provided for by irrevocably depositing with the trustee or a paying agent for such Electric Revenue Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) Defeasance Obligations maturing, or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will insure the availability of sufficient moneys to make such payment, or a combination thereof, whichever Energy Northwest deems to be in its best interest, and all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to the Electric Revenue Bond with respect to which such deposit is made shall have been paid or the payment thereof provided for to the satisfaction of the Trustee and said paying agents.

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 theretofore 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 2014-C Bonds. The Series 2014-C 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 2014-C Bond certificate will be issued for each maturity of each Series of the Series 2014-C 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 2014-C 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 2014-C Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2014-C 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 2014-C 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 2014-C Bonds, except in the event that use of the book entry-entry system for the Series 2014-C Bonds is discontinued.

To facilitate subsequent transfers, all Series 2014-C 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 2014-C 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 2014-C Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C Bond certificates will be printed and delivered.

With respect to Series 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C Bond is registered on the Bond Register, as the holder and absolute owner of such Series 2014-C Bond for the purpose of payment of principal and interest with respect to such Series 2014-C Bond, for the purpose of giving notices of redemption and other matters with respect to such Series 2014-C Bond, for the purpose of registering transfers with respect to such Series 2014-C 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 2014-C Bonds.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville entered into written agreements (the "Disclosure Agreements") for the benefit of the holders and beneficial owners of the Series 2014-C Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreements, which apply to any capitalized term used in the Disclosure Agreements, the following capitalized terms shall have the following meanings:

"BPA Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the Series 2014-C Bonds in the following tables in Appendix A under the headings "POWER SERVICES": "Bonneville Power Services' Ten Largest Customers by Sales" and "Historical Average PF Preference Rates," "TRANSMISSION SERVICES": "Transmission Services' Ten Largest Customers By Sales," "BONNEVILLE FINANCIAL OPERATIONS": "Historical Capital Spending by Program by Fiscal Year," "Historical Capital Funding by Source and Fiscal Year," "Historical Federal System Operating Revenue and Operating Expense Compared to Historical Stream Flows," "Federal System Statement of Revenues and Expenses," "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments" and "Bonneville's Fiscal Year-End Financial Reserves."

"Energy Northwest Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the Series 2014-C Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of July 1, 2014" 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, 2014:

(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, 2014:

(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 2014-C 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 2014-C Bonds;

vii. Modifications to rights of Series 2014-C Bondholders, if material;

viii. Optional, contingent or unscheduled calls of any Series 2014-C 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 2014-C 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 (i) reference to items (iii) and (x) above that no debt service reserves or property secure payment of the 2014-C Bonds, and (ii) reference to items (iv) and (v) above that no credit enhancements or liquidity facilities secure payment of the 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C 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 2014-C Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

ENERGY NORTHWEST • PROJECT 1 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2014-C AND PROJECT 3 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2014-C

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