NEW ISSUE **BOOK-ENTRY-ONLY**

In the opinion of Special Counsel, interest on the Series 2014 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). See "TAX MATTERS – Certain U.S. Federal Income Tax Considerations" herein. In the further opinion of Special Counsel, interest on the Series 2014 Bonds is exempt from present State of Oregon personal income taxation. See "TAX MATTERS – Certain State of Oregon Income Tax Considerations" herein.

$193,075,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 2)
Series 2014 (Federally Taxable)

Dated: Date of Delivery Due: September 1, as shown on inside cover

The Series 2014 Bonds will be special obligations of the Issuer payable solely from the trust estate pledged therefor which trust estate includes amounts derived from rental payments paid to the Issuer pursuant to a Lease-Purchase Agreement between the Issuer and the United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

Bonneville's payments under the Lease-Purchase Agreement will be made solely from the Bonneville Fund. The Lease-Purchase Agreement provides that Bonneville's obligation to pay the rental payments and all amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project financed with the proceeds of the Series 2014 Bonds is operating or operable. Bonneville's payment obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America. See "THE ISSUER – Limited Obligation."

The Series 2014 Bonds are being issued for the principal purpose of acquiring certain transmission facilities to be leased to Bonneville. See "PURPOSE OF ISSUANCE AND USE OF PROCEEDS."

The Series 2014 Bonds will bear interest as shown on the inside cover, payable on March 1, 2015 and semi-annually thereafter on September 1 and March 1 of each year.

The Series 2014 Bonds will be issued in fully registered form and will be initially registered only in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"), which will act as securities depository for the Series 2014 Bonds. Individual purchases in principal amounts of $5,000 or multiples thereof will be made only through the book-entry-only system maintained by DTC through brokers and dealers who are, or act through, DTC Participants. The purchasers of the Series 2014 Bonds will not receive certificates representing their interest in the Series 2014 Bonds. Ownership interests in the Series 2014 Bonds will be shown on, and transfers of Series 2014 Bonds will be effected only through, records maintained by DTC and its participants. Payments of principal of, premium, if any, and interest on the Series 2014 Bonds will be made to owners by DTC through its participants.

The Trustee for the Series 2014 Bonds is U.S. Bank National Association.

The Series 2014 Bonds are subject to redemption prior to maturity as described herein.

The Series 2014 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of the proceedings authorizing the Series 2014 Bonds by Orrick, Herrington & Sutcliffe LLP, and to certain other conditions. Certain legal matters will be passed upon for the Issuer by Monahan, Grove & Tucker, Milton-Freewater, Oregon, and 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. The Series 2014 Bonds are expected to be delivered through the facilities of DTC on or about December 18, 2014.

J.P. Morgan

Citigroup **BofA Merrill Lynch** **TD Securities LLC** **Wells Fargo Securities**

December 10, 2014

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES AND PRICES

$193,075,000

Year (September 1)	Principal Amount	Interest Rate	Price	CUSIP[†] Number
2024	$37,015,000	3.221%	100%	73474TAB6
2025	70,345,000	3.371	100	73474TAC4
2027	85,715,000	3.521	100	73474TAD2

[†] The CUSIP number is provided by CUSIP Global Services, managed on behalf of the American Bankers Association by Standard & Poor's. The CUSIP number is not intended to create a database and does 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 the Issuer nor the Underwriters take responsibility for the accuracy of the CUSIP number.

The information contained in this Official Statement has been obtained from the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") and in certain limited instances from the Port of Morrow, Oregon (the "Issuer") and other sources which are deemed to be reliable. This Official Statement is submitted in connection with the sale of the securities referred to herein, and may not be reproduced or be used, in whole or in part, for any other purpose. The delivery of this Official Statement at any time does not imply that the information herein is correct as of any time subsequent to its date.

No dealer, salesman or any other person has been authorized by the Issuer or J.P. Morgan Securities LLC and the other Underwriters (collectively the "Underwriters") to give any information or to make any representations other than as contained in this Official Statement in connection with the offering described herein and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. This Official Statement does not constitute an offer of any securities, other than those described on the cover page, or an offer to sell or a solicitation of an offer to buy in any jurisdiction in which it is unlawful to make such offer, solicitation or sale.

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

The Issuer makes no representation as to the accuracy or completeness of any information in this Official Statement and takes no responsibility for its contents, other than the information relating to the Issuer under the headings "THE ISSUER," "VALIDATION," and "LEGAL MATTERS."

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS WHICH STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE MARKET PRICE OF THE SERIES 2014 BONDS.

This Official Statement contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "estimate," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. A number of important factors affecting Bonneville's business 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.

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OFFICIAL STATEMENT

$193,075,000
Port of Morrow, Oregon
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 2),
Series 2014 (Federally Taxable)

INTRODUCTORY STATEMENT

This Official Statement provides information concerning the issuance by the Port of Morrow, Oregon (the "Issuer" or the "Port") of $193,075,000 principal amount of its Transmission Facilities Revenue Bonds, Series 2014 (the "Series 2014 Bonds"). The Series 2014 Bonds are being issued to finance the costs of acquiring certain transmission facilities (the "Project"), as further described herein under "THE PROJECT," to be owned by the Issuer and leased to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville").

The Issuer will execute a Lease-Purchase Agreement with Bonneville dated December 18, 2014 (the "Lease-Purchase Agreement") pursuant to which the Issuer will lease the Project to Bonneville. The Series 2014 Bonds will be issued under an Indenture of Trust dated as of December 1, 2014 (the "Indenture") between the Issuer and U.S. Bank National Association, as trustee (the "Trustee"). Under the Indenture, the Issuer will assign to the Trustee certain rights under the Lease-Purchase Agreement, including the right to receive rental payments from Bonneville in amounts at least sufficient to pay when due the principal of, and interest on, the Series 2014 Bonds.

Brief descriptions and summaries of the Series 2014 Bonds, the Lease-Purchase Agreement and the Indenture follow in this Official Statement. These descriptions and summaries do not purport to be complete and are subject to and qualified by reference to the provisions of the complete documents, copies of which are available at the offices of the Trustee at Global Corporate Trust Services, 555 SW Oak Street, PD-OR-P4TD, Portland, Oregon 97204. Appendices A and B to this Official Statement have been furnished by Bonneville and contain information concerning the business of Bonneville. Capitalized terms not otherwise defined herein shall have the meanings given to such terms in the Indenture.

THE ISSUER

General

The Issuer, a port district located in Morrow County, Oregon, was organized in 1957 under Oregon Revised Statutes, Section 777, as amended. The Issuer's boundaries, approximately 2,049 square miles, are coterminous with Morrow County. To the north, the Issuer is bordered by the Columbia River and is transected by Interstate 84 and Union Pacific railroad mainline. Both the highway and the railroad pass through Boardman, the location of the Port's administrative office and a portion of its industrial park.

Port districts in the State of Oregon are authorized to acquire, hold, use, enjoy and convey, lease or otherwise dispose of real and personal property, or any interest therein, necessary or convenient in carrying out its powers. Port powers include the right to acquire rights of way for the placing of transmission lines over which to carry electric energy, with the full power to lease and sell the same, together with the lands upon which they are situated, whether held by the port in its governmental capacity or not.

The Port's major mission remains economic development and creation of jobs for the cities of Boardman, Lexington, Heppner, Ione and Irrigon. The Port's area has approximately 11,300 residents. A five member Board of Commissioners governs the Port.

Board of Commissioners

Name	Title	Occupation	Term Began	Term Ends
Don Russell	President	Real Estate Investments	07/01/13	06/30/17
Joe Taylor	Vice-President	Farmer	07/01/13	06/30/17
Larry Lindsay	Secretary/Treasurer	Farmer	07/01/11	06/30/15
Jerry Healy	Commissioner	Retired	07/01/13	06/30/17
Marvin Padberg	Commissioner	Farmer	07/01/11	06/30/15

Administration

The Port employs a manager, who is responsible for all management and administrative functions. The manager has a staff of 44 full-time equivalent employees to assist in administrative and facility maintenance activities.

Limited Obligation

The Series 2014 Bonds shall not be payable out of any funds of the Issuer other than those pledged therefor but shall be payable by the Issuer solely from the Trust Estate. Nothing in the Series 2014 Bonds, in the Lease-Purchase Agreement or in the Indenture or any other agreement or binding document shall be considered as pledging any other funds or assets of the Issuer. All right, title, and interest of the Issuer in and to the Trust Estate shall be pledged to the Trustee for the benefit of Series 2014 Bondholders for the payment of the principal of, premium, if any, and interest on the Series 2014 Bonds in accordance with their terms and provisions of the Indenture. THE SERIES 2014 BONDS, TOGETHER WITH THE INTEREST THEREON, SHALL BE SPECIAL LIMITED OBLIGATIONS OF THE ISSUER PAYABLE SOLELY FROM THE TRUST ESTATE PLEDGED UNDER THE INDENTURE; AND THE SERIES 2014 BONDS SHALL NOT CONSTITUTE A DEBT OR PLEDGE OF THE FULL FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE STATE OR ANY POLITICAL SUBDIVISION OF THE STATE OR A LOAN OF THE CREDIT OF ANY OF THE FOREGOING WITHIN THE MEANING OF ANY CONSTITUTIONAL OR STATUTORY LIMITATION AND SHALL NEVER CONSTITUTE OR GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER, THE STATE OR ANY POLITICAL SUBDIVISION OF THE STATE. NO OWNER OF ANY SERIES 2014 BONDS SHALL HAVE THE RIGHT TO COMPEL ANY EXERCISE OF TAXING POWER OF THE ISSUER, THE STATE OR ANY POLITICAL SUBDIVISION OF THE STATE, INCLUDING THE ISSUER, TO PAY THE SERIES 2014 BONDS OR THE INTEREST THEREON. THE LEASE-PURCHASE AGREEMENT SHALL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR A CHARGE AGAINST THE GENERAL CREDIT OR TAXING POWER OF THE ISSUER, THE STATE OR ANY POLITICAL SUBDIVISION OF THE STATE WITHIN THE MEANING OF ANY CONSTITUTIONAL OR STATUTORY LIMITATION.

VALIDATION

On March 15, 2012, the Circuit Court of the State of Oregon of the County of Morrow, in a validation procedure brought by the Issuer, determined among other things, that the Issuer has the authority to issue revenue bonds in one or more series and to enter into financing agreements to finance or refinance the costs of acquisition, installation and/or construction of future or existing transmission facilities which are now or will be leased to Bonneville and that upon execution and delivery thereof, all bonds issued in connection with said transmission facilities, including the Series 2014 Bonds, and any leases or indentures executed in connection with such transmission facilities, including the Indenture and Lease-Purchase Agreement, will be valid, legal and binding obligations in accordance with their terms.

The judgment binds and permanently enjoins all persons from the institution of any action or proceeding challenging the validity of any bonds, indentures or leases in connection with such transmission facilities or any matters adjudicated in such validation actions or which could have adjudicated in such actions. The validation judgment became effective on April 15, 2012.

PURPOSE OF ISSUANCE AND USE OF PROCEEDS

Pursuant to a lease-purchase agreement and a related construction agreement dated as of March 1, 2008, between Bonneville and the Northwest Infrastructure Financing Corporation III ("NIFC III"), NIFC III provided for the acquisition, construction, installation and equipping of certain transmission assets (as described below, the "Project") and leased the Project to Bonneville. NIFC III financed such acquisition, construction, installation and equipping through a credit agreement with a commercial bank, and secured its obligations under such credit agreement with the lease-purchase agreement by and between NIFC III, as lessor, and Bonneville, as lessee, and the payments from Bonneville thereunder.

The proceeds from the sale of the Series 2014 Bonds will be used by the Issuer to acquire the Project from NIFC III. NIFC III will use the funds received from the Issuer to pay the indebtedness incurred under said credit agreement. Upon receipt of the acquisition payment, NIFC III will relinquish all of its rights and interests in the Project and irrevocably transfer such rights and interests to the Issuer. The proceeds from the sale of the Series 2014 Bonds will also be used by the Issuer to pay the costs of issuance of the Series 2014 Bonds (including Underwriters' discount) and certain administrative costs of the Issuer. The costs of issuance and such administrative costs are $1,514,485.66.

THE PROJECT

As described herein under "THE LEASE-PURCHASE AGREEMENT," the Project will be leased by the Issuer to the United States Department of Energy, acting by and through the Administrator of the Bonneville Power Administration. The Project consists solely of fixtures and/or equipment that are a part of electric transmission system facilities located in the Pacific Northwest region of the United States. The Project includes twelve rebuilt transmission lines with conductor, disconnect switches, insulators, overhead ground wire, surge arresters, steel towers, steel poles, or wood poles. The Project also includes one static volt amp reactive compensating system and additions or replacements at thirty-six Federal Columbia River Power System substations for aluminum bus, battery systems, battery chargers, circuit switchers, control cable, current transformers, disconnect switches, power circuit breakers, power circuit switchers, power transformers, relays, shunt capacitors, shunt reactors, supervisory control and acquisition data systems, station service transfer switches, station service transformers, steel towers, steel poles, voltage transformers, or wood poles. These additions, replacements, and improvements were acquired, constructed, installed or equipped for the purpose of maintaining system reliability and providing enhanced electric transmission service. Bonneville's leasehold interests in the Project and its rights and obligations in connection therewith are a part of the "Federal Transmission System" as described in Bonneville's organic statutes. Bonneville has obtained and holds, in the name of the United States of America, all of the rights of way and other real property interests on which the Project is sited. These real property interests are not subject to condemnation by any state or local authority.

Under the Lease-Purchase Agreement and the Indenture, the definition of the Project may be amended from time to time without the consent of the holders of the Series 2014 Bonds. See "THE LEASE-PURCHASE AGREEMENT - Changing the Definition of the Project."

The Series 2014 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described under "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2014 BONDS – Trust Estate." Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2014 Bonds. See "THE PROJECT."

SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2014 BONDS

Trust Estate

Under the terms of the Indenture, the Series 2014 Bonds are payable solely but equally and ratably from and are secured solely but equally and ratably by the Trust Estate which consists of (i) all right, title and interest of the Issuer in and to the Lease-Purchase Agreement, including all rental payments, revenues and receipts payable or receivable thereunder, excluding, however, the Issuer's Reserved Rights, which rights may be enforced by the Issuer and the Trustee jointly or severally; (ii) all right, title and interest of the Issuer in and to the Project, subject to the Lease-Purchase Agreement; (iii) all moneys and securities from time to time held by the Trustee under the terms of the Indenture including amounts set apart and transferred to the Project Fund, the Bond Fund or the Reserve Fund, and all investment earnings of any of the foregoing, subject to disbursements from the Project Fund, the Bond Fund, or the Reserve Fund in accordance with the provisions of the Lease-Purchase Agreement and the Indenture; (iv) any and all other property of every kind and nature from time to time which was heretofore or hereafter will be by delivery or by writing of any kind conveyed, mortgaged, pledged, assigned or transferred, as and for additional security under the Indenture, by the Issuer or by any other person, firm or corporation with or without the consent of the Issuer, to the Trustee which is hereby authorized to receive any and all such property at any time and at all times to hold and apply the same subject to the terms of the Indenture.

Pursuant to the Lease-Purchase Agreement between Bonneville and the Issuer, Bonneville is required to make rental payments in the amounts set forth in schedules set forth in the Lease-Purchase Agreement which schedules will provide for rental payments at times and in amounts more than sufficient to pay the principal of and interest and all other amounts due on the Series 2014 Bonds. See herein "THE LEASE-PURCHASE AGREEMENT" and "THE INDENTURE." Such rental payments are irrevocably pledged by the Issuer pursuant to the Indenture for the payment of principal or redemption premium, if any, of and interest on the Series 2014 Bonds. The Lease-Purchase Agreement provides that such rental payments will be made directly to the Trustee for deposit in the Bond Fund.

The Lease-Purchase Agreement provides that Bonneville's obligation to pay the rental payments and all other amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project is operating or operable. Bonneville's obligation to make the rental payments will continue until September 1, 2027, unless sooner terminated or extended in accordance with the provisions of the Lease-Purchase Agreement, and is coterminous with the final maturity of the Series 2014 Bonds. **Bonneville's obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.**

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease-Purchase Agreement. The Issuer and Bonneville will declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer will waive any rights it may have as a secured party with respect to the Project. The Series 2014 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described above. Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2014 Bonds. See "THE PROJECT."

Source of Bonneville's Payments: 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. 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 - "BONNEVILLE POWER ADMINISTRATION—Bonneville Financial Operations—The Bonneville Fund."

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

Payments by Bonneville under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations or the Series 2014 Bonds intended to be or are they secured by the full faith and credit of the United States of America.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are to be made from net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal Columbia River Power System (the "Federal System"), other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the United States Corps of Engineers and the United States Bureau of Reclamation for certain costs allocated to electric 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 2014 payment responsibility to the United States Treasury in full and on time for the 31st consecutive year.

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 for operating and maintenance expenses, including Bonneville's payments under the Lease-Purchase Agreement, 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 payments relating to the Lease-Purchase Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

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 scheduled payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has not deferred such payments since 1983.

Bonneville also has a substantial number of agreements with Preference Customers, as hereinafter described in Appendix A - "BONNEVILLE POWER ADMINISTRATION—GENERAL," pursuant to which Bonneville has an obligation to provide credits against power and transmission purchases made from Bonneville by such customers. Under these "net billing" agreements, related Bonneville Preference Customers ("Participants") have the obligation to make payments to two third-parties (Energy Northwest and the City of Eugene, Oregon, Water and Electric Board ("EWEB")) to meet the costs of certain nuclear generating projects, one of which is currently operating. In return, Bonneville has an obligation to the Participants to provide payment credits ("net billing credits") against the monthly power and transmission bills issued by Bonneville. The net billing credits reduce the amount of cash that Bonneville would otherwise have to pay its cash payment obligations. The occurrence of net billing credits is determined in part by the availability of funds to Energy Northwest and EWEB, apart from net billing, to cover the related projects' costs. As described below, Bonneville has entered into certain direct payment agreements that result in direct payments from Bonneville to Energy Northwest and EWEB for all related project costs. These agreements have enabled Energy Northwest and EWEB to reduce net billing to zero. However, if Bonneville is unable or fails to make direct payments, or if certain other conditions occur, net billing would be re-established. For additional descriptions of Bonneville's substantial net billing arrangements, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt," "—POWER SERVICES—Description of the Generation Resources of the Federal System," "—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Energy Northwest Net Billed Projects Bonds," and "—BONNEVILLE FINANCIAL OPERATIONS—Direct Pay Agreements." Bonneville has and may enter into other crediting commitments that are similar to net billing credits in that they reduce the amount of revenue in cash that Bonneville receives. See APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Electric Power Conservation" and "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States

Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) net billed project costs to the extent covered by net billing credits, (2) cash payments out of the Bonneville Fund to cover all required payments incurred by Bonneville pursuant to law, including payments by Bonneville under the Lease-Purchase Agreement, but excluding payments to the United States Treasury and (3) payments to the United States Treasury. For further information, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

THE SERIES 2014 BONDS

General

The Series 2014 Bonds will be issued originally as a single global certificate for each maturity registered to DTC, or its nominee, Cede & Co., to be held in DTC's book-entry-only system. So long as the Series 2014 Bonds are held in the book-entry-only system, DTC (or a successor securities depository) or its nominee will be the registered owner of the Series 2014 Bonds for all purposes of the Indenture, the Series 2014 Bonds and this Official Statement. Interest on the Series 2014 Bonds will be payable only through participants or indirect participants in DTC so long as the Series 2014 Bonds are held in the book-entry-only system. The Series 2014 Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. See "Book-Entry-Only System" below.

The Series 2014 Bonds are dated the date of their delivery, and mature on September 1 in the years and in the principal amounts shown on the inside cover page of this Official Statement. The Series 2014 Bonds will bear interest, computed on the basis of a 360-day year of twelve 30-day months, at the rates shown on the inside cover page of this Official Statement. The Series 2014 Bonds are subject to redemption prior to maturity as set forth below. Additional Bonds may be issued under the Indenture. Such Bonds, together with the Series 2014 Bonds, are referred to as the "Bonds."

Interest on the Series 2014 Bonds will be payable on March 1 and September 1 of each year, commencing March 1, 2015, to the persons in whose name the Series 2014 Bonds are registered on the fifteenth day of the month preceding the interest payment date; provided that overdue interest shall be paid to the persons in whose name such Series 2014 Bonds are registered by close of business on the fifth Business Day next preceding the date of payment of the defaulted interest. So long as the Series 2014 Bonds are held in the book-entry-only system, all payments of principal of and premium, if any, and interest are required to be made by the Trustee to DTC in immediately available funds for further distribution to beneficial owners of the Series 2014 Bonds.

Book-Entry-Only System

DTC will act as securities depository for the Series 2014 Bonds. The Series 2014 Bonds will be issued as fully-registered Series 2014 Bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Series 2014 Bond will be issued for the Series 2014 Bonds for each maturity, in the aggregate 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, 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 Participants are on file with the Securities and Exchange Commission ("SEC"). More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Series 2014 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2014 Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2014 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 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 Bonds, except in the event that use of the book-entry-only system for the Series 2014 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2014 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of the Series 2014 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2014 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2014 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Series 2014 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the Series 2014 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2014 Bond documents. For example, Beneficial Owners of Series 2014 Bonds may wish to ascertain that the nominee holding the Series 2014 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the Trustee and request that copies of notices be provided directly to them. THE ISSUER, BONNEVILLE AND THE TRUSTEE WILL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT AND INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO THE SERIES 2014 BONDS.

Redemption notices will be sent to DTC. If less than all of the Series 2014 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 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Series 2014 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Series 2014 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee, on payable dates in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Trustee, or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the Series 2014 Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2014 Bonds are required to be printed and delivered as described in the Indenture.

The Issuer, at the direction of Bonneville, 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 Bond certificates will be printed and delivered to DTC.

THE ISSUER, THE TRUSTEE, BONNEVILLE AND THE UNDERWRITERS SHALL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO ANY DIRECT OR INDIRECT PARTICIPANT, ANY BENEFICIAL OWNER OR ANY OTHER PERSON CLAIMING A BENEFICIAL OWNERSHIP INTEREST IN THE SERIES 2014 BONDS UNDER OR THROUGH DTC OR ANY DTC PARTICIPANT, OR ANY OTHER PERSON WHICH IS NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A HOLDER, WITH RESPECT TO THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT; THE PAYMENT BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF ANY AMOUNT IN RESPECT OF THE PRINCIPAL OF, PREMIUM, IF ANY, OR INTEREST ON THE SERIES 2014 BONDS; ANY NOTICE WHICH IS PERMITTED OR REQUIRED TO BE GIVEN TO OWNERS UNDER THE INDENTURE; THE SELECTION BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF ANY PERSON TO RECEIVE PAYMENT IN THE EVENT OF A PARTIAL REDEMPTION OF THE SERIES 2014 BONDS; ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS AN OWNER; OR ANY OTHER PROCEDURES OR OBLIGATIONS OF DTC UNDER THE BOOK-ENTRY-ONLY SYSTEM.

SO LONG AS CEDE & CO. (OR SUCH OTHER NOMINEE AS MAY BE REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC) IS THE REGISTERED OWNER OF THE SERIES 2014 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS OR OWNERS OR REGISTERED HOLDERS OR REGISTERED OWNERS OF THE SERIES 2014 BONDS MEANS CEDE & CO., AS AFORESAID, AND DOES NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2014 BONDS.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2014 Bonds, payment of principal, interest and other payments on the Series 2014 Bonds to Direct and Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Series 2014 Bonds and other related transactions by and between DTC, the Direct and Indirect Participants and the Beneficial Owners is based solely on information provided by DTC. Accordingly, no representations can be made concerning these matters, and neither the Direct nor Indirect Participants nor the Beneficial Owners should rely on the foregoing information with respect to such matters, but should instead confirm the same with DTC.

Optional Redemption

The Series 2014 Bonds are subject to redemption prior to their respective maturities at the option of the Issuer (with the approval of Bonneville), in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The "Make-Whole Redemption Price" is the greater of (i) the issue price of the Series 2014 Bonds as shown on the cover page of this Official Statement (but not less than 100% of the principal amount of the Series 2014 Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2014 Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2014 Bonds are to be redeemed, discounted to the date on which such Series 2014 Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below) plus 20 basis points, plus accrued and unpaid interest on the Series 2014 Bonds to be redeemed on the redemption date.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2014 Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price (defined below), as calculated by the Designated Investment Banker (defined below).

"Comparable Treasury Issue" means, with respect to any redemption date for a particular Series 2014 Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2014 Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such Series 2014 Bonds to be redeemed.

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

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

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

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2014 Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Issuer, the Trustee and Bonneville by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

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

Partial Redemption

If less than all of the Series 2014 Bonds are to be redeemed, the Issuer may select the maturity or maturities to be redeemed. The Indenture provides that the portion of any Series 2014 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 Bonds for redemption, the Trustee will treat each such Series 2014 Bonds as representing that number of such Series 2014 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2014 Bonds to be redeemed in part by $5,000.

The particular Series 2014 Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2014 Bonds are registered in book-entry-only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2014 Bonds, if less than all of a maturity of the Series 2014 Bonds of a maturity are called for redemption, the particular Series 2014 Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2014 Bonds are held in book-entry-only form, the selection for redemption of such Series 2014 Bonds shall be made in accordance with the operational arrangements of DTC then in effect. It is the Issuer's intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between the Issuer and the Beneficial Owners be made in accordance with the pro rata pass-through distribution of principal basis described below. However, the Issuer can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among registered owners on such basis. If the DTC operational arrangements do not allow for the redemption of the Series 2014 Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2014 Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

If the Series 2014 Bonds are not registered in book-entry-only form, any redemption of less than all of a maturity of the Series 2014 Bonds shall be allocated among the registered owners of such Series 2014 Bonds as nearly as practicable in proportion to the principal amounts of the Series 2014 Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2014 Bonds. This will be calculated based on the following formula:

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

Notice of Redemption

Notice of redemption of any Series 2014 Bonds is to be given by the Trustee by first-class mail not less than 30 days nor more than 60 days before the redemption date to the registered owners of the Series 2014 Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2014 Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2014 Bonds which are to be redeemed, whether or not such notice is actually received. Failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the Series 2014 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2014 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 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2014 Bonds on the redemption date and the Series 2014 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. The Issuer may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry-only system is in effect with respect to the Series 2014 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 Bonds of a maturity are to be redeemed, DTC or its successor and Participants and Indirect Participants (as such terms are defined herein under the heading "THE SERIES 2014 BONDS – Book-Entry-Only System") will determine the particular ownership interests of Series 2014 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 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2014 Bonds.

Neither the Issuer, 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 Bonds, or that they will do so on a timely basis.

THE LEASE-PURCHASE AGREEMENT

The following is a summary of certain provisions of the Lease-Purchase Agreement, to which reference is made for the detailed provisions thereof.

Rental Payments

Bonneville agrees under the Lease-Purchase Agreement to pay to the Trustee rental payments for deposit in the Bond Fund created under the Indenture in the amounts set forth in schedules to the Lease-Purchase Agreement, which schedules provide for rental payments more than sufficient for the payment of the principal of, and interest on, the Series 2014 Bonds. The obligation of Bonneville to make all payments provided in the Lease-Purchase Agreement is stated to be absolute and unconditional. See “SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2014 BONDS” herein.

Bonneville has also agreed to pay as additional rent under the Lease-Purchase Agreement, all Impositions, which are defined as all taxes and assessments, general and specific, if any, levied and assessed upon or against the Project, the Lease-Purchase Agreement, any estate or interest of the Issuer or Bonneville in the Project or transfer of such estate or interest, or the rental payments under the Lease-Purchase Agreement during the term of the Lease-Purchase Agreement, and all assessments and other governmental charges and impositions whatsoever, foreseen or unforeseen, ordinary or extraordinary, under any present or future law, and charges for public or private utilities or other charges incurred in the occupancy, use, operation, maintenance or upkeep of the Project.

Indemnity

Bonneville agrees to pay all reasonable costs and expenses of the Issuer incurred in connection with the Lease-Purchase Agreement and to protect and indemnify the Issuer against and hold the Issuer harmless from (i) all costs and expenses arising from or relating to compliance with environmental laws and regulations and orders of governmental agencies applicable to the Project or arising from or relating to mitigation, remediation, or abatement of environmental impacts, (ii) any and all claims (whether in tort, contract or otherwise), demands, expenses (including reasonable attorneys’ fees) and liabilities for any loss, damage, injury and liability of every kind and nature and however caused, including any liability arising from failure to comply with applicable environmental laws, regulations or orders applicable to the Project, and (iii) taxes of any kind and by whomsoever imposed on the Issuer in respect of the Project or the Bonds, in each case arising from or relating to the Project or resulting from, arising out of, or in any way connected with the financing of the costs of the Project and marketing, issuance or sale of the Bonds for such purpose (including amounts payable by the Issuer pursuant to its indemnification of the Trustee, the Bond Registrar and the Paying Agents); provided, however, that, Bonneville has no indemnification obligation for any such costs, expenses claims, demands, taxes or liabilities arising from the intentional misrepresentation or willful misconduct of the Issuer. Such indemnification set forth above shall be binding upon Bonneville for any and all claims, demands, expenses, liabilities and taxes set forth above and shall survive the expiration or termination of the Lease-Purchase Agreement.

Operation of the Project

The Issuer has no control over, and no obligation with respect to, the Project, including the operation, maintenance, repair, replacement or use of the Project. Bonneville will pay all costs of operating the Project and will make all decisions regarding the operation or use of the Project. Bonneville may, in its discretion, transfer operational control to a regional transmission organization or other entity; provided that Bonneville is required to remain liable under the Lease-Purchase Agreement. Bonneville may suspend, delay, or terminate operation of, take out of service, or dismantle the Project, or any portion thereof, in its discretion, provided that the Lease-Purchase Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the rental payments or other amounts payable by Bonneville under the Lease-Purchase Agreement. Bonneville will hold, in the name of the United States, all easements, rights of way, and any other interests in land under the Project and the Issuer shall have no rights therein.

Covenants

In the Lease-Purchase Agreement, Bonneville agrees, among other things, to pay all costs of maintaining the Project in the same manner in which Bonneville maintains similar facilities that it owns; to keep the Project free of liens, except as provided in the Lease-Purchase Agreement; to pay charges and assessments against the Project; to comply with law; to indemnify the Issuer and pay its fees and expenses as well as those of the Trustee; to furnish to the Trustee, any requesting holder of more than $1,000,000 of Series 2014 Bonds, and the Issuer, a copy of its financial statements, and to notify the Issuer and the Trustee of the occurrence of any Event of Default under the Lease-Purchase Agreement.

Damage, Destruction and Condemnation

If the Project is damaged, destroyed or condemned, there will be no reduction in the rental payments or other amounts payable under the Lease-Purchase Agreement. The Issuer shall have no obligation to rebuild, replace, repair or restore the Project. Bonneville will not be obligated to rebuild, replace, repair or restore the Project or any portion thereof or purchase the Project or any portion thereof following a loss event so long as the Lease-Purchase Agreement shall remain valid, binding and enforceable on Bonneville following such loss event. If Bonneville elects to rebuild, replace, repair or restore the Project or any portion thereof, it shall do so with its own or others' funds. Any proceeds of insurance or condemnation awards or recoveries of claims against contractors (or an amount equal to such proceeds, awards or recoveries) received by the Issuer or Bonneville shall be, as directed by Bonneville, deposited into the Project Fund or the Bond Fund for use to pay or reimburse the costs of repair or replacement of the related portions of the Project, for the prepayment of rental payments thereafter coming due, or as may otherwise be permitted in the Indenture; provided, however, that, if the foregoing proceeds (or amounts equal thereto) are received by Bonneville in respect of facilities that were a part of the Project when the damage or the basis for the claim originally arose but which facilities were subsequently removed from the definition of the Project, any proceeds (or amounts equal to such proceeds) received by Bonneville shall be retained by Bonneville as its own funds.

Termination of the Lease-Purchase Agreement

Upon the redemption or defeasance in whole of all outstanding Bonds in accordance with the Indenture, Bonneville may terminate the Lease-Purchase Agreement.

Defaults

The Lease-Purchase Agreement provides that any one or more of the following events will constitute an "Event of Default":

(a) Failure by Bonneville to pay when due any rental payment that has become due and payable under the Lease-Purchase Agreement;

(b) Failure of Bonneville to pay any amount due under the Lease-Purchase Agreement (other than under paragraph (a) above) and continuance of such failure for thirty (30) days, after notice of such failure is given to Bonneville or the Issuer or the Trustee; and

(c) Failure by Bonneville to observe or perform any covenant, condition or agreement on its part to be observed or performed under the Lease-Purchase Agreement, other than as described in (a) or (b) above, for a period of 30 days after written notice specifying such failure and requesting that it be remedied is given to Bonneville by the Issuer, the Trustee or the holders of more than 25% of the Bonds, or if the failure is such that it cannot be remedied within 30 days, Bonneville fails to proceed to cure with reasonable diligence; provided, however, that such cure must be made within 60 days after receipt by Bonneville of such written notice.

Remedies

Upon the occurrence and continuance of an Event of Default under the Lease-Purchase Agreement, the Issuer (with respect to its reserved rights) or the Trustee where so provided, but subject to the statutory limitations on remedies against Bonneville, may take whatever action at law or in equity permitted by law to be taken against Bonneville as may appear necessary or desirable to collect the rental payment then due and thereafter to become due, or to enforce performance or observance of any obligations, agreements or covenants of Bonneville under the Lease-Purchase Agreement.

Any amounts collected pursuant to action taken under this paragraph will be paid to the Trustee for deposit into the Bond Fund and applied in accordance with the provisions of the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the provisions of the Indenture) to Bonneville.

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease-Purchase Agreement. The Issuer and Bonneville declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer waives any rights it may have as a secured party with respect to the Project.

Statutory Limitation on Legal Remedies against Bonneville

The Issuer acknowledges in the Lease-Purchase Agreement that its remedies against Bonneville are limited to those provided under federal law, which provides that the exclusive remedy for breach of contract by Bonneville is a judgment for money damages. The Issuer and Bonneville have agreed that such damages shall be measured by the amounts required to be paid by Bonneville under the Lease-Purchase Agreement and not by the market value of the Project or a leasehold interest in the Project.

Options

Under the Lease-Purchase Agreement, Bonneville has the option, at any time and from time to time, to make advance rental payments which, at the direction of Bonneville, will be deposited into the Bond Fund and held to make the next maturing scheduled payments of principal and interest on the Bonds or applied to redeem all or a portion of the Bonds, all in accordance with the terms of the Indenture. Bonneville has the option, at any time and from time to time, to purchase all or any portion of the Project by making a purchase option payment equal to the amount necessary to redeem all or the applicable portion of the Bonds on the next redemption date. Such purchase option may be assigned by Bonneville without the consent of the Issuer. The Project is divided into components as provided in the Lease-Purchase Agreement and Bonneville may exercise its purchase option with respect to any component or portion thereof by making a purchase option payment equal to the redemption price of the percentage of Bonds of the applicable maturity of the Bonds allocable to such component or portion. Bonneville or its assignee will exercise its option to make such advance rental payments or such purchase option by delivering a written notice of an authorized representative of Bonneville to the Trustee in accordance with the Indenture, with a copy to the Issuer, setting forth (i) the amount of the advance rental payment or purchase option payment, (ii) the principal amount of Bonds Outstanding requested to be redeemed with such advance rental payment (if any) or purchase option payment (which principal amount shall be in such minimum amount or integral multiple of such amount as shall be permitted in the Indenture), and (iii) the date on which such principal amount of Bonds are to be redeemed. Such advance rental payment to be applied to redeem Bonds or to make any such purchase option payment will be paid to the Trustee in legal tender on or before the redemption date and will be an amount which, when added to the amount on deposit in the Bond Fund and available therefor, will be sufficient to pay the Redemption Price of the Bonds to be redeemed, together with interest to accrue on the Bonds to be redeemed to the date fixed for redemption and all expenses of the Issuer, the Bond Registrar, the Trustee and the Paying Agents (including reasonable fees and expenses of counsel to the Issuer, the Bond Registrar, the Trustee and the Paying Agents) in connection with such redemption. After any purchase of a portion of the Project, the rental payment payable pursuant to the Lease-Purchase Agreement will be reduced by the percentage equal to the percentage that the portion of the Project purchased is to the entire Project (as shown in a schedule to the Lease-Purchase Agreement) or by such other amount agreed to by the Issuer and Bonneville with the consent of the Trustee; provided that, in either case, such amount may not be less than an amount sufficient to pay debt service on the Outstanding Bonds when due.

Bonneville may assign to another entity the options described in the preceding paragraph provided that all other provisions relating to the exercise of the options, including the provisions describe above, shall be complied with upon exercise of the options. It is possible that Bonneville could enter into a new lease-purchase agreement with the assignee of the option(s), and the assignee could exercise the option(s) to purchase or pre-pay all or a portion of the properties constituting the Project. In this circumstance, the assignee of the option(s) could pledge rental payments from Bonneville under the new lease to secure the issuance of debt the proceeds of which would be used to fund the pre-payment or purchase occasioned by the exercise of the option(s).

Force Majeure

The obligations of the parties under the Lease-Purchase Agreement, except the obligation of Bonneville to make payments required to be made under the Lease-Purchase Agreement and to indemnify the Issuer, are subject to suspension during periods of force majeure.

Assignment or Sublease

Bonneville may assign, partially assign (for instance, Bonneville may assign the Lease with respect to certain identified portions of the Project) or transfer the Lease-Purchase Agreement or sublet the whole or any part of the Project so long as Bonneville will remain liable to the Issuer for the payment of all rental payments and other payments under the Lease-Purchase Agreement and for the full performance of all of the terms, covenants and conditions of the Lease. Bonneville will furnish or cause to be furnished to the Issuer a copy of any such assignment, transfer or sublease in substantially final form within ten (10) days prior to the date of execution thereof. Bonneville may also enter into contracts relating to the use of the Project as provided in the Lease-Purchase Agreement. Funds received by or on account of Bonneville in connection with a sublease, assignment, partial assignment or transfer in accordance with this paragraph shall be Bonneville's funds.

Amendment

The Lease-Purchase Agreement may not be amended except by an instrument in writing signed by Bonneville and the Issuer and consented to by the Trustee in accordance with the Indenture. See "THE INDENTURE - Amendment of the Lease-Purchase Agreement." A change in the definition of the Project pursuant to the Lease-Purchase Agreement will not constitute an amendment to the Lease-Purchase Agreement. See "THE LEASE-PURCHASE AGREEMENT – Changing the Definition of the Project."

Changing the Definition of the Project

Under the Lease-Purchase Agreement and the Indenture, the definition of the Project may be amended from time to time, without the consent of the holders of the Bonds, including to exclude components or portions thereof or to add other facilities; provided, however, that, Bonneville's rental payments shall remain unaffected by such a change in definition. By means of changing the definition of the Project, it is possible that, among other things, facilities that were once portions of the Project, may be excluded from the definition and transferred to Bonneville's ownership, or transferred to another entity's ownership, but in any such instance the Lease-Purchase Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the rental payments or other amounts payable by Bonneville under the Lease-Purchase Agreement.

More particularly, the Issuer will commit to agree that, at the request of Bonneville, it will amend the definition of a Project to (i) change the location of the Project or any component or portion thereof or (ii) to remove any part of the Project or (iii) to replace all or any part of such Project with facilities having a similar value. The Project definition may be otherwise amended as may be agreed to by the Issuer and Bonneville. The amendment of the Project definition shall not entitle Bonneville to any abatement or reduction in the rentals and other amounts payable by Bonneville under the Lease-Purchase Agreement. In the event of a re-definition of the Project, there is no obligation or special right to call any of the Series 2014 Bonds prior to their final maturity.

Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired and Bonneville shall not be required to deposit in the Bond Fund or otherwise pay to the Issuer any amounts received by Bonneville from such sale, assignment or disposition. Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is not obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired and the funds received from such sale, assignment or disposition shall be paid over to the Bond Fund to be applied to the payment of principal of, and interest and premiums, if any, on, the Series 2014 Bonds, and to the extent the amounts are so applied, they will constitute a contribution to rental payments otherwise payable by Bonneville. Finally, if a portion of the Project becomes worn out or obsolete, or otherwise is taken out of service or retired prior to the final maturity of the Series 2014 Bonds, the Project may be redefined through an amendment to the definition of the Project. If such portion of the Project is replaced, the facilities so replacing the portion may be owned by Bonneville or another project owner or replaced with funds obtained by the Issuer under a lease with Bonneville separate and apart from the Lease-Purchase Agreement. See “THE PROJECT.”

The right of Issuer and Bonneville to change the definition of the Project is separate and apart from the amendment of the Lease-Purchase Agreement. See “THE LEASE-PURCHASE AGREEMENT - Amendment,” and “THE INDENTURE - Amendment of the Lease-Purchase Agreement.”

THE INDENTURE

The following is a summary of certain provisions of the Indenture, to which reference is made for the detailed provisions thereof.

Trust Estate

Pursuant to the Indenture, (i) all of the Issuer’s right, title and interest in and to the Lease-Purchase Agreement, including all amounts (excluding payments for indemnification and certain other payments thereunder) to be received by the Issuer pursuant to the Lease-Purchase Agreement, (ii) all of the right, title and interest of the Issuer in and to the Project, (iii) all moneys and securities held by the Trustee under the Indenture including amounts held by the Trustee in the Project Fund, the Bond Fund and the Reserve Fund established under the Indenture, and (iv) any and all other property that may be conveyed to the Trustee as security for the Bonds, are assigned and pledged to the Trustee to secure the payment of the principal of, premium, if any, and interest on the Bonds.

Project Fund

The proceeds of the sale of the Series 2014 Bonds will be deposited in the Project Fund to be held by the Trustee. Moneys in the Project Fund will be applied to finance the acquisition of the Project from NIFC III, and to pay expenses incurred in connection with the issuance and sale of the Series 2014 Bonds, and for other costs of the Project upon requisitions signed by an authorized representative of Bonneville or, with respect to certain costs of issuance, an authorized representative of the Issuer.

Bond Fund

The Indenture establishes with the Trustee a Bond Fund into which will be deposited accrued interest, lease rent payments paid by Bonneville and other receipts to be paid into the Bond Fund. The Bond Fund will be used (except as otherwise provided in the Indenture) for the payment of principal of, premium, if any, and interest on the Bonds.

Reserve Fund

The Indenture establishes with the Trustee a Reserve Fund into which will be deposited any amounts remaining on deposit in the Bond Fund on the Business Day following each interest payment date on the Bonds. The Reserve Fund will be used for the payment of amounts payable by or to the Issuer upon requisitions signed by an authorized representative of the Issuer. There is no requirement in the Indenture that withdrawals from the Reserve Fund be replenished or that the Reserve Fund be maintained at a particular amount.

Investments

Amounts in any fund or account established under the Indenture may be invested or reinvested by the Trustee upon the written direction of an authorized representative of the Issuer at the direction of Bonneville in obligations or securities specified in the Indenture.

Additional Bonds

So long as the Lease-Purchase Agreement is in effect, Additional Bonds may be issued under the Indenture from time to time in the discretion of the Issuer for the purpose of (i) providing funds to repair, relocate, replace, rebuild or restore the Project in the event of damage, destruction or taking by eminent domain, (ii) providing extensions, additions or improvements to the Project, or (iii) refunding outstanding Bonds. It is a condition to the issuance of Additional Bonds that the amounts payable by Bonneville under the Lease-Purchase Agreement will be adjusted to provide for the payment of principal of, premium, if any, and interest on the Additional Bonds. Additional Bonds shall be equally and ratably secured under the Indenture with the Series 2014 Bonds.

Events of Default and Remedies

Each of the following is an "Event of Default" under the Indenture:

(a) failure in the payment of interest on any Bond when due;

(b) failure in the payment of the principal or redemption premium, if any, of, or sinking fund installment for, any Bond when due, whether at the stated maturity thereof, upon any proceedings for redemption thereof or otherwise;

(c) failure by the Issuer to perform or observe any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds (except as set forth in (a) or (b) above), and the continuance thereof for a period of thirty days after written notice to the Issuer and Bonneville from the Trustee or the holders of more than 25% of the aggregate principal amount of Bonds then outstanding; provided that, if the default can be remedied but not within the applicable period, the Issuer or Bonneville proceeds with diligence to cure the default, it shall not be an Event of Default; or

(d) an Event of Default under the Lease-Purchase Agreement.

Pursuant to the Lease-Purchase Agreement, the Issuer has granted to Bonneville full authority for the account of the Issuer to perform any covenant or obligation the non-performance of which is alleged in any notice received by Bonneville to constitute a default under the Indenture, in the name and stead of the Issuer with full power to do any and all things and acts to the same extent that the Issuer could do and perform any such things and acts with power of substitution. The Trustee agrees to accept such performance by Bonneville as performance by the Issuer.

Upon the occurrence and continuance of an Event of Default, the Trustee may, and at the direction of the holders of over 25% of the outstanding Bonds shall, take actions at law or equity to protect and enforce its rights and the rights of the Bondholders. If requested by the holders of over 25% of the outstanding Bonds, the Trustee shall maintain actions to prevent impairment of the security of the Indenture whether or not there has occurred an Event of Default. **The Indenture does not provide for the remedy of acceleration of payment of the Bonds.**

The holders of a majority in aggregate principal amount of Bonds then outstanding have the right, at any time, by an instrument or instruments in writing delivered to the Trustee, to direct the method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceeding under the Indenture; provided, that such direction shall not be otherwise than in accordance with the provisions of law and the Indenture.

No holder of any Bond shall have any right to institute any suit, action or proceeding in equity or at law for the enforcement of the Indenture or for the execution of any trust thereof or any remedy under the Indenture, unless the Trustee has been notified of the default, and the holders of over 25% of aggregate principal amount of Bonds then outstanding have made a written request to the Trustee and have offered reasonable opportunity either to exercise the powers granted in the Indenture or to institute such action, suit or proceeding in its own name, and unless they also have offered to the Trustee adequate security and indemnity and the Trustee refuses to comply within 60 days. Nothing in the Indenture shall, however, affect or impair the right of any Bondholder to payment of the principal or redemption price, if applicable, of, sinking fund installments for, and interest on any Bond at and after the maturity thereof, or the obligation of the Issuer to pay the principal or redemption price, if applicable, of, sinking fund installments for, and interest on the Bonds to the respective holders thereof at the time, place, from the source and in the manner expressed in the Bonds and the Indenture.

Waivers of Events of Default

The Trustee shall waive any Event of Default under the Indenture and its consequences only upon the written request of the holders of a majority in aggregate principal amount of the Bonds then outstanding; provided, however, that there shall not be waived without the consent of the holders of all of the Bonds then outstanding (i) any default in the payment of the principal of any outstanding Bond when due or (ii) any default in the payment when due of the interest on any outstanding Bond, unless, prior to such waiver, all arrears of interest, with interest (to the extent permitted by law) at the rate borne by the Bonds on overdue installments of interest, and all arrears of payments of principal, when due, as the case may be, and all expenses of the Trustee in connection with such default, shall have been paid or provided for, or in case any proceeding taken by the Trustee on account of any such default shall have been discontinued or abandoned or determined adversely, then, and in every such case the Issuer, the Trustee, Bonneville and the Bondholders shall be restored to their former positions and rights under the Indenture, respectively, but no such waiver or rescission shall extend to any subsequent or other Event of Default, or impair any right consequent thereon.

Application of Moneys after Default

All moneys received by the Trustee pursuant to any right given or action taken under the provisions of the Indenture shall, after payment of any amounts due under the Lease-Purchase Agreement and after the payment of the costs and expenses of the proceedings resulting in the collection of such moneys and of the fees, expenses, liabilities and advances incurred or made by the Trustee, be deposited in the Bond Fund. Such amounts will be applied first to the payment of interest and then to the payment of principal or redemption price, if any, which shall have become due.

Amendments of the Indenture

The Issuer and the Trustee may, without the consent of, or notice to, the Bondholders, enter into indentures supplemental to the Indenture (a) to cure any ambiguity or formal defect or omission in the Indenture; (b) to grant to or confer upon the Trustee for the benefit of the Bondholders any additional rights, remedies, powers, authority or security that may be lawfully granted; (c) to add additional covenants of the Issuer; (d) to add limitations and restrictions to be observed by the Issuer; which are not contrary to or inconsistent with the Indenture as theretofore in effect; (e) to confirm, as further assurance, any pledge under the Indenture, or to subject to the lien or pledge of the Indenture additional revenues, properties or collateral; (f) to effect any other change in the Indenture which is not to the material prejudice of the Trustee or the Bondholders; (g) to authorize the issuance of a Series of Additional Bonds; or (h) to modify, amend or supplement the Indenture or any indenture supplemental thereto in such manner as to permit the qualification thereof under the Trust Indenture Act of 1939 or any similar federal statute then in effect or to permit the qualification of the Bonds for sale under the securities laws of the United States of America or of any of the states of the United States of America and, if they so determine, to add to the Indenture or any indenture supplemental thereto such other terms, conditions and provisions as may be permitted by the Trust Indenture Act of 1939 or similar federal statute.

With the consent of Bonneville and the holders of not less than a majority in aggregate principal amount of the Bonds then outstanding, the Issuer and the Trustee may enter into such other supplemental indentures as the Issuer shall deem necessary and desirable, provided there shall be no (i) change in the times, amounts or currency of payment of the principal of, sinking fund installments for, redemption premium, if any, or interest on any outstanding Bonds, a change in the terms of redemption or maturity of the principal of or the interest on any outstanding Bonds, or a reduction in the principal amount of or the redemption price of any outstanding Bond or the rate of interest thereon, or any extension of the time of payment thereof, without the consent of the holder of such Bond, (ii) the creation of a lien upon or pledge of the Trust Estate other than the liens or pledge created by the Indenture except as provided in the Indenture with respect to Additional Bonds, (iii) a preference or priority of any Bond or Bonds over any other Bond or Bonds, (iv) a reduction in the aggregate principal amount of Bonds required for consent to such supplemental indenture, or (v) a modification, amendment or deletion with respect to any of the terms set forth above, without, in the case of items (ii) through (v) above, the written consent of 100% of the holders of the outstanding Bonds.

Amendment of the Lease-Purchase Agreement

The Issuer and the Trustee may, without the consent of or notice to the Bondholders, consent to any amendment, change or modification of the Lease-Purchase Agreement (a) for the purpose of curing any ambiguity, formal defect or omission therein, (b) which, by the terms of the Lease-Purchase Agreement, may be made without the consent of the Bondholders, or (c) which is not materially to the prejudice of the Trustee or the Holders of the Bonds. The Trustee shall not consent to any other amendment, change or modification of the Lease-Purchase Agreement without the consent of the holders of at least a majority in principal amount of the Bonds then outstanding, provided, however, that without the written approval of the holders of 100% of the Bonds, there shall be no amendment, change or modification to the obligation of Bonneville to make rental payments under the Lease-Purchase Agreement with respect to the Bonds. Separate and apart from the amendment of the Lease-Purchase Agreement, the Issuer and Bonneville will reserve the right to amend the definition of the Project. See THE LEASE-PURCHASE AGREEMENT – Changing the Definition of the Project."

Discharge of the Indenture

If the principal or redemption price of, sinking fund installments for, and interest on, the Bonds then outstanding shall have been paid in full or shall be deemed to have been paid in full, and all other amounts required to be paid to the Trustee under the Indenture shall be paid in full, then the pledge of any lease rentals, revenues or receipts from or in connection with the Project under the Indenture shall cease, terminate and be void and the Trustee shall cancel and discharge the lien and security interest of the Indenture and execute and deliver to the Issuer and Bonneville such instruments as shall be required to cancel and discharge the Indenture and pay over and deliver to the Issuer all money or securities held by it not required for payment of the Bonds.

Bonds or portions thereof for the payment (either by redemption or at maturity) of which sufficient moneys shall have been irrevocably deposited with the Trustee, shall be deemed to be paid within the meaning of the Indenture if (A) there shall have been deposited with the Trustee either moneys in an amount which shall be sufficient, or obligations of the United States government or obligations the principal of and interest on which are guaranteed by the United States government, the principal of and the interest on which when due without reinvestment will provide moneys which, together with the moneys, if any, deposited with the Trustee at the same time, shall be sufficient, to pay when due the principal, Sinking Fund Installment or Redemption Price, if applicable, and interest due and to become due on said Bonds or portion of all Outstanding Bonds on and prior to the redemption date or maturity date thereof, as the case may be; (B) no Event of Default shall exist on the date of such deposit or shall occur as a result of such deposit; and (C) the Issuer has delivered to the Trustee and any Paying Agent a certificate signed by an Authorized Representative and an opinion of counsel, each stating that the conditions set forth in subsections (A) and (B) above have been complied with.

CONTINUING DISCLOSURE

Bonneville, as an "obligated person" within the meaning of Section (b)(5)(i) of Securities and Exchange Commission Rule 15c2-12 under the Securities Exchange Act of 1934, as amended (17 CFR Part 240, § 240.15c2-12) (the "Rule"), has undertaken in the Continuing Disclosure Certificate to provide certain information. A copy of the form of Continuing Disclosure Certificate is contained in Appendix D herein.

Bonneville has not failed to comply with all previous undertakings with respect to the Rule in any material respect in the preceding five years; however, until 2012 Bonneville had not included in its reports an update of the table of Operating Federal System Projects (contained in Appendix A under "POWER SERVICES – Operating Federal Systems Projects"), as provided under certain (but not all) of its previous undertakings. The information in such table does not vary substantially from year to year and 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 listed events is set forth in Appendix D "FORM OF CONTINUING DISCLOSURE CERTIFICATE."

The Issuer has not undertaken any continuing disclosure obligation with respect to the Bonds.

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2014 Bonds.

RATINGS

Moody's Investors Service ("Moody's") and Fitch Ratings ("Fitch") have assigned the Series 2014 Bonds the ratings of "Aa1" and "AA", respectively. Ratings were applied for by Bonneville and certain information was supplied by Bonneville to such rating agencies to be considered in evaluating the Series 2014 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 Bonds.

UNDERWRITING

J.P. Morgan Securities LLC and the other Underwriters (the "Underwriters") of the Series 2014 Bonds have jointly and severally agreed, subject to certain conditions, to purchase the Series 2014 Bonds from the Issuer at an underwriters' discount of $943,858.43 and to reoffer the Series 2014 Bonds at the initial public offering price set forth on the cover page hereof. The Underwriters have agreed to purchase all of the Series 2014 Bonds if any are purchased. The Series 2014 Bonds may be offered and sold to certain dealers (including dealers depositing Series 2014 Bonds into investment accounts) and to others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Series 2014 Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriters. Bonneville has agreed to pay certain out-of-pocket expenses of the Underwriters.

The Underwriters have provided the following information for inclusion in this Official Statement.

J.P. Morgan Securities LLC ("JPMS"), an Underwriter of the Series 2014 Bonds, has informed the Issuer 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 Bonds, at the original issue prices. Pursuant to the Dealer Agreement, (if applicable to this transaction), CS&Co. will purchase the Series 2014 Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any Series 2014 Bonds that CS&Co. sells.

Citigroup Global Markets Inc., an underwriter of the Series 2014 Bonds, has informed the Issuer 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 Bonds.

Wells Fargo Securities is the trade name for certain securities-related capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including Wells Fargo Bank, National Association. Wells Fargo Bank, National Association ("WFBNA"), one of the underwriters of the Series 2014 Bonds, has entered into an agreement (the "Distribution Agreement") with its affiliate, Wells Fargo Advisors, LLC ("WFA"), for the distribution of certain municipal securities offerings, including the Series 2014 Bonds. Pursuant to the Distribution Agreement, WFBNA will share a portion of its underwriting or remarketing agent compensation, as applicable, with respect to the Series 2014 Bonds with WFA. WFBNA also utilizes the distribution capabilities of its affiliates, Wells Fargo Securities, LLC ("WFSLLC") and Wells Fargo Institutional Securities, LLC ("WFIS"), for the distribution of municipal securities offerings, including the Series 2014 Bonds. In connection with utilizing the distribution capabilities of WFSLLC, WFBNA pays a portion of WFSLLC's expenses based on its municipal securities transactions. WFBNA, WFSLLC, WFIS, and WFA are each wholly-owned subsidiaries of Wells Fargo & Company.

The Underwriters and their 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. See herein "CERTAIN RELATIONSHIPS." The Underwriters and their affiliates have, from time to time, performed, and may in the future perform, various investment banking services for 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 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 secured by payments from Bonneville.

CERTAIN RELATIONSHIPS

J.P. Morgan Securities LLC, an Underwriter of the Series 2014 Bonds, is an affiliate of JPMorgan Chase Bank, N.A., which provided the loan to NIFC III to construct and acquire the Project and has extended credit in other transactions supported by obligations of Bonneville under related agreements.

Merrill Lynch, Pierce, Fenner & Smith Incorporated, an Underwriter of the Series 2014 Bonds, is an affiliate of Bank of America, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

Citigroup, an Underwriter of the Series 2014 Bonds, is an affiliate of Citigroup, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

TD Securities LLC, an Underwriter of the Series 2014 Bonds, is an affiliate of Toronto Dominion Bank, which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

WFBNA is serving as both an Underwriter of the Series 2014 Bonds and has extended credit in other transactions supported by obligations of Bonneville under related agreements.

TAX MATTERS

Certain U.S. Federal Income Tax Considerations

At the closing, Special Tax Counsel is expected to deliver its opinion, based upon an analysis of existing laws, regulations, rulings and court decisions, that, interest on the Series 2014 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the Code. Special Tax Counsel is expected to express no opinion regarding any other federal tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2014 Bonds.

If the Issuer defeases any Series 2014 Bond, such Series 2014 Bond may be deemed to be retired and "reissued" for U.S. federal income tax purposes as a result of the defeasance. In that event, the beneficial owner of the Series 2014 Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the beneficial owner's adjusted U.S. federal income tax basis in the Series 2014 Bond. See "THE INDENTURE – Discharge of the Indenture."

Circular 230. Under 31 C.F.R. part 10, the regulations governing practice before the IRS (Circular 230), the Issuer and its tax advisors are (or may be) required to inform prospective investors that:

i. any advice contained herein is not intended or written to be used, and cannot be used, by any taxpayer for the purpose of avoiding penalties that may be imposed on the taxpayer;

ii. any such advice is written to support the promotion or marketing of the Series 2014 Bonds and the transactions described herein; and

iii. each taxpayer should seek advice based on the taxpayer's particular circumstances from an independent tax advisor.

Certain State of Oregon Income Tax Considerations

In the opinion of Special Counsel, interest on the Series 2014 Bonds is exempt from present State of Oregon personal income taxation.

LEGAL MATTERS

Legal matters incident to the authorization and issuance of the Series 2014 Bonds are subject to the unqualified approving opinion of Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Issuer by Monahan, Grove & Tucker, Milton-Freewater, Oregon, and 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, member of Norton Rose Fulbright.

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Port of Morrow, Oregon (the "Issuer" or the "Port of Morrow") herein by Bonneville for use in the Official Statement, dated December 10, 2014, furnished by the Issuer (the "Official Statement") with respect to its Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 2), Series 2014 (Federally Taxable) (the "2014 Bonds"). The Project is described in the Official Statement under "THE PROJECT." 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 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 United States of America, Department of Energy ("DOE"). Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-federally-owned and -operated projects, including an operating nuclear generating station (the "Columbia Generating Station") owned by Energy Northwest (a joint operating agency of Washington State) 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 2015 of approximately 10,361 annual average megawatts (defined below) under median water conditions and approximately 8,199 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 power 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 about 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 which Bonneville sells power. For example, Bonneville estimated in Fiscal Year 2014 that on a planning basis in Operating Year 2015, it will meet 8,162 annual average megawatts of loads, of which approximately 85 percent would be Preference Customer loads. By contrast, Bonneville estimated approximately seven percent would be federal agency loads and DSI loads, and approximately eight 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 of America, Department of Treasury ("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 conformity 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 scheduled payment responsibility to the United States Treasury of $670 million in full and on time for Bonneville's fiscal year ended September 30, 2014 ("Fiscal Year 2014"). In addition, Bonneville prepaid an additional $321 million principal amount of its federal repayment obligation. 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 rental payments under the Lease-Purchase Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. For a description of the Lease-Purchase Agreement, see the Official Statement under the heading "THE LEASE-PURCHASE AGREEMENT." 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 rental payments under the Lease-Purchase Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2014 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 315.75 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 Rates," 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

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 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.

The Final 2014-2015 Rates reflect an increase in 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. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2014-2015," and "TRANSMISSION SERVICES—General - Bonneville's Transmission and Ancillary and Control Area Services Rates." 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."

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 (the "2016-2017 Rate Period"). Bonneville has issued its 2016-2017 Initial Rate Proposal, which begins an administrative process that will culminate in a 2016-2017 Final Rate Proposal and a record of decision. Bonneville expects to submit the 2016-2017 Final Rate Proposal and record of decision to FERC by the end of July 2015. The 2016-2017 Initial Rate Proposal proposes, on a preliminary basis, that power rates in such period increase by approximately 6.7 percent and its transmission and related rates in such period increase by approximately 5.6 percent, in each case over the average rates now in effect. The 2016-2017 Final Rate Proposal could differ, perhaps substantially, from the 2016-2017 Initial Rate Proposal.

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 operations & maintenance expense ("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.

Consistent with longstanding policy, Bonneville's 2016-2017 Final Rate Proposal will be 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. Bonneville's United States Treasury payments are payable after Bonneville's non-federal payment obligations such as the rental payments under the Lease-Purchase Agreement. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Regional Cooperation Debt

In August 2014, Energy Northwest issued approximately $269 million in bonds ("Energy Northwest Series 2014-C Bonds") that refinanced outstanding debt and increased the weighted average maturities of outstanding bonds that are secured by Net Billing Agreements among Bonneville, Energy Northwest and over 100 individual Participants. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Energy Northwest Net Billed Projects Bonds." Bonds and other debt instruments issued by Energy Northwest and secured by Net Billing Agreements are referred to herein as "Net Billed Bonds." The Net Billed Bonds are also included in Bonneville's audited financial statements as "Non-Federal Debt." See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Energy Northwest Net Billed Projects Bonds." As a result of Energy Northwest's August 2014 refinancing, the average maturity of the Net Billed Bonds increased to more closely match the originally expected useful lives of related Energy Northwest Net Billed Projects. The refinancing made available to Bonneville revenues near the end of Fiscal Year 2014, 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 prepaid $321 million of its repayment obligations with respect to amounts appropriated by Congress for federally-owned hydroelectric facilities of the Federal System. The federal repayment obligations so prepaid bore interest at a rate higher than the rates of interest on the Energy Northwest Series 2014-C Bonds. Bonneville estimates that the interest expense savings is approximately $9.5 million annually through Fiscal Year 2023.

Bonneville has asked Energy Northwest to consider similar refinancings of Net Billed Bonds in the future. The Energy Northwest Executive Board is considering this request, which is known as the regional cooperation debt refinancings. As with the Energy Northwest Series 2014-C Bonds, these proposed refinancing efforts would extend maturities to more closely match the original expected useful lives of the related Energy Northwest Net Billed Projects. Future regional cooperation debt transactions, if implemented, would make available Bonneville revenues in future years to prepay a portion of its repayment obligation for appropriated federal investments in the Federal System, to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury, and for other debt management actions to be determined through a public process. Bonneville estimates that in aggregate the potential principal amount of regional cooperation debt refinancings could exceed $3.2 billion.

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 $2.7 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 2014.

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 for repayment. 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 2015 (August 1, 2014 through July 31, 2015), the total Federal System would be capable of producing approximately 8,199 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes approximately 6,797 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,000 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including co-generation, hydropower, renewable, and non-utility generation projects), and approximately 402 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 2015."

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 2015 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 2015."

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 2015, the Federal System is estimated to generate seasonal surplus (secondary) energy of 1,346 annual average megawatts, assuming average water conditions (median water flows). In years with high water conditions (high water flows) the amount of seasonal surplus (secondary) energy could be as much as 2,453 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 National Oceanic and Atmospheric Administration ("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 United States of America, Department of Interior, Fish and Wildlife Service ("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 2015." 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 402 annual average megawatts in Operating Year 2015.

Operating Federal System Projects for Operating Year 2015

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 2015, 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 2015[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	5,069	2,649	2,431	1,950
Hungry Horse	1952	4	319	140	97	76
Other Reclamation Projects[6]		16	32	169	150	119
1. Total Reclamation Projects		53	5,420	2,958	2,678	2,145
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,374	1,465	1,357	1,119
John Day	1968	16	2,295	1,393	1,079	808
The Dalles w/o Fishway[7]	1957	24	1,830	1,004	813	605
Bonneville	1938	20	921	567	558	397
McNary	1953	14	1,036	696	627	482
Lower Granite	1975	6	737	389	282	175
Lower Monumental	1969	6	810	459	319	182
Little Goose	1970	6	859	401	294	179
Ice Harbor	1961	6	586	307	232	158
Libby	1975	5	483	276	229	186
Dworshak	1974	3	434	282	217	145
Other Corps Projects[8]		20	206	282	260	216
2. Total Corps Projects		153	12,571	7,521	6,267	4,652
3. Idle Federal Capacity[9]			(7,449)	0	0	0
4. Total Reclamation and Corps Projects (line 1 + line 2 + line 3)		**206**	**10,542**	**10,479**	**8,945**	**6,797**
Non-Federally-Owned Projects						
Columbia Generating Station[10]	1984	1	1,130	878	878	878
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**	**1,020**	**1,004**	**1,000**
Federal Contract Purchases						
6. Total Bonneville Contract Purchases[13]		**n/a**	**702**	**420**	**412**	**402**
Total Federal System Resources						
7. Total Federal System Resources (line 4 + line 5 + line 6)		**225**	**12,435**	**11,919**	**10,361**	**8,199**

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

(1) Operating Year 2015 is August 1, 2014 through July 31, 2015. 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 scheduled for refueling in Operating Year 2015 and, therefore, will provide approximately 878 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 Department of Water Resources' 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 "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

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 parties with which Bonneville has commercial power-related arrangements that are not based on Bonneville's statutory obligations ("Market Counterparties"). See "—Market Counterparties and Exports of Surplus Power to the Pacific Southwest." 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 315.75 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 2014. 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 2014)

Customer Name (Class)	Approximate % of Sales
Snohomish County PUD No. 1 (Preference)	8%
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)	4%
ALCOA, Inc. (DSI)	4%
Powerex Corp. (Independent Power Producer)	4%
Clark Public Utilities (Preference)	4%
Eugene Water & Electric Board (Preference)	3%
Iberdrola Renewables Inc. (Wind Developer)	2%

(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 26.6 percent of Federal System generation that is recovered in Tier 1 PF Rates (see "—Tiered Rates for Long-Term Preference Contracts."). Preliminary forecasts for Fiscal Year 2015 indicate that loads met under Load Following products will be approximately 3,325 annual average megawatts. Loads met by Slice/Block will be approximately 3,694 annual average megawatts in total, about half of which is expected to be for the Block portion (and about 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 embedded 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 6,944 annual average megawatts for Fiscal Year 2015. Actual Tier 1 Loads were 6,925 annual average megawatts in Fiscal Year 2014 (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).

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 74 annual average megawatts of Tier 2 Loads in Fiscal Year 2015. In Fiscal Year 2013 and Fiscal Year 2014, Tier 2 Loads were 57 annual average megawatts and 18 annual average megawatts, respectively. 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 Rates, 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, Bonneville 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."

In addition, starting in Fiscal Year 2016, Bonneville plans to make available an electric power conservation billing credit program where Bonneville would provide fixed monthly credits on participating Preference Customers' power bills in exchange for independent conservation activities funded by the Preference Customer. If such a program is implemented, Bonneville would begin providing electric power conservation billing credits in Fiscal Year 2016, if any, for expenditures to be incurred by the participating Preference Customers in Fiscal Year 2016. Electric power conservation billing credits involve fixed, equal, monthly credits to the Preference Customer power bills and would be derived assuming a hypothetical financing of two years' of annual conservation expenditures incurred by the Preference Customer. The monthly billing credits would be provided starting in the fiscal year of the related conservation expense and continue for twelve years. (Twelve years is the period that Bonneville amortizes, and borrows for, conservation expenditures.) To the extent that conservation expenditures are funded through electric power conservation billing credits, Bonneville would avoid the use of borrowing for such costs from the United States Treasury or using Non-Federal Debt.

To date, only a few Preference Customers have indicated a high level of interest in participating in an electric conservation billing credits program. Depending on the interest level of Preference Customers and other factors, it is possible that up to $20 million of independent conservation activity expense could be incurred by Preference Customers annually for Fiscal Year 2016 and Fiscal Year 2017, costs of which would be eligible for annual aggregate electric power conservation billing credits in an amount not-to-exceed $1.7 million and $3.4 million in Fiscal Year 2016 and Fiscal Year 2017, respectively. Bonneville has received public comments on the program and draft billing credit policy and expects to issue a record of decision regarding electric power conservation billing credits in December 2014.

Renewable Energy. Bonneville presently purchases a total of approximately 60 annual average megawatts from various wind energy projects in Wyoming, Oregon, and Washington and small amounts of power from a solar photovoltaic project. 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 beyond October 1, 2016.

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 began at $259 million in each of Fiscal Years 2012 and 2013, and increases over time to $286 million in Fiscal Year 2028. Past erroneous overpayments by Bonneville to Regional IOUs 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 2014, the aggregate overpayment of Residential Exchange Program benefits that have not yet been recouped by Bonneville (and conveyed to Preference Customers) was approximately $364 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' 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 2012 through 2014.

Fish and Wildlife Financial Impacts By Type
(Fiscal Years 2014-2012, dollars in millions)

	2014	**2013**	**2012**
Direct Costs	$ 464	$ 461	$ 453
Estimated Operational Impacts[1]:			
Replacement Power purchases	196	86	38
Foregone Power Revenues	123	135	152
Total Fish and Wildlife	**$ 783**	**$ 682**	**$ 643**

[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 Fisheries 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 recovering 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 2014, 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 by the Corps 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 federally-owned dams of the Federal System 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. In developing the Final 2016-2017 Rate Proposal, Bonneville will make assumptions of the possible range of expected incremental costs that could arise under the 2014 Columbia River System Supplemental Biological Opinion and that such assumptions will be 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.

<u>Willamette River Project Biological Opinion</u>. 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 historical 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 $77 million, $84 million, and $104 million in Fiscal Years 2012, 2013, and 2014 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 $232 million, and Federal System capital investment was $37 million, in each case in Fiscal Year 2014. Bonneville forecasts that in Fiscal Year 2015, expenses and capital program investments will be $260 million and $52 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 sold to Preference Customers for their loads 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 certain 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."

Consistent with longstanding policy, Bonneville's Final 2014-2015 Rates were 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 obligations such as the rental payments under the Lease-Purchase Agreement. Rental payments are made from cash available in the Bonneville Fund. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met." Bonneville's revenues in cash are reduced if and to the extent that Bonneville provides credits to customers' bills, as arises under Net Billing Agreements and certain other agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Energy Northwest Net Billed Projects Bonds," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Electric Power Conservation," and BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments."

Some important factors that led 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.

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 "Cost Recovery Adjustment Clause" (or, "CRAC") that can increase certain power (and certain ancillary services) rate levels during the rate period. The CRAC 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 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 or 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. The CRAC did not trigger for Fiscal Year 2014 or Fiscal Year 2015.

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 Reserves Available for Risk, or "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—Management Discussion of Operating Results—Fiscal Year 2014—Reserves Available for Risk," Bonneville's Financial Reserves," and "—Banking Relationship between the United States Treasury and Bonneville."

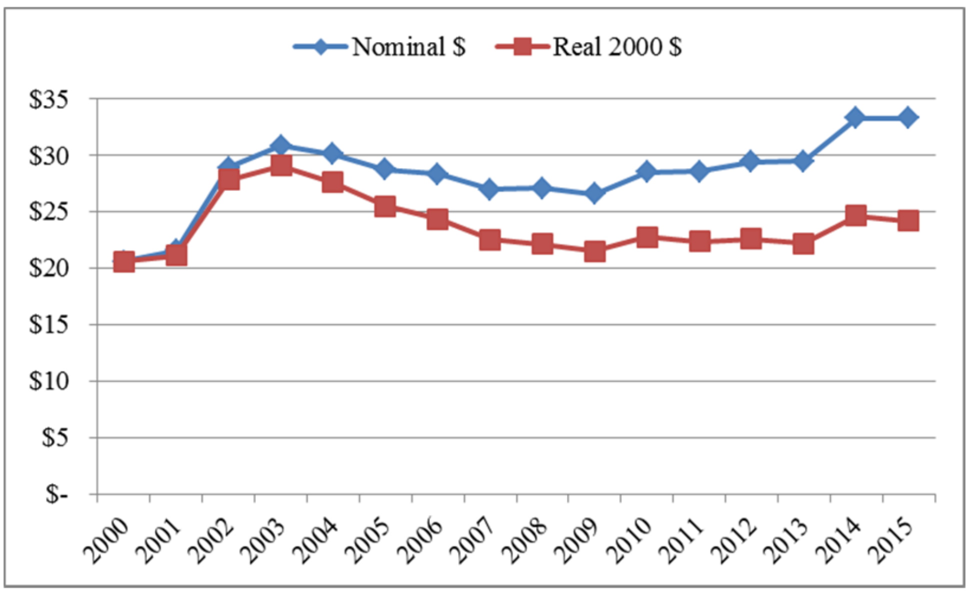
The Final 2014-2015 Rates for power continue the availability of a feature parallel to, but the reverse of, the CRAC, referred to as the Dividend Distribution Clause ("DDC"). The DDC could decrease certain power and ancillary services rate levels in either year of the rate period, also based on financial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

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 $932 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 2014.

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 generating 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. From November 2014 through November 2015, the DC line's capacity is and will be reduced from 3,100 megawatts to 2,000 megawatts during a planned replacement of certain facilities at Bonneville's Celilo Converter Station in Umatilla County, Oregon. Bonneville does not expect the reduction in capacity to have a material adverse impact on Federal Transmission System reliability, on Transmission Services revenue, or Bonneville's power transactions. Bonneville expects that the replacement of the Celilo Converter Station facilities will be financed through the issuance of approximately $400 million in bonds secured by Bonneville's payments under a lease-purchase agreement. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program—Possible Non-Federal Debt Activities in the Near Future—Future Lease-Purchases."

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 2015 through 2023 averaging approximately $404 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 $37 million in Fiscal Year 2014 and will be $36 million in Fiscal Year 2015. 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.

Where applicable and in a manner consistent with Bonneville's Tariff, Bonneville 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 2014. 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 2014)

Customer Name (Class)	Approximate % of Sales
Puget Sound Energy Inc. (IOU)	12%
PacifiCorp (IOU)	11%
Portland General Electric Company (IOU)	9%
Powerex Corp. (Power Marketer)	7%
City of Seattle, City Light Dep't. (Preference)	5%
Snohomish County PUD No. 1 (Preference)	4%
Iberdrola Renewables Inc. (Wind Developer)	4%
Pacific Northwest Generating Cooperative (Preference)	2%
Hermiston Power LLC (Power Marketer)	2%
Clark Public Utilities (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. Cost allocation involves the mandatory (non-voluntary) contribution by utilities to the cost of the related 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, did not specifically address Bonneville's issues regarding mandatory cost allocation, and denied Bonneville's request for clarification or rehearing. Certain other parties filed petitions for judicial review of Orders 1000, 1000-A, and 1000-B. Oral argument was held March 20, 2014, before the United States Court of Appeals for the District of Columbia Circuit. The United States Court of Appeals for the District of Columbia Circuit affirmed Order 1000. Certain other parties have filed a request for rehearing of the decision by the United States Court of Appeals for the District of Columbia Circuit. The request for rehearing is pending. 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 statutes. 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.

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 pending FERC's response to Bonneville's July 22, 2013 request for clarification or rehearing. On September 18, 2014, FERC issued an order in response to Bonneville's July 22, 2013 request for clarification or rehearing, the other planning participants' request for rehearing, and the other Northwest utilities December 17, 2013 compliance filing, FERC ruled that Bonneville could participate in regional planning with the Northwest utilities, that Bonneville would not be subject to mandatory cost allocation provisions and could either accept or reject a cost allocation for a proposed project, and that Bonneville could not seek cost allocation from other transmission owners for Bonneville's projects. On November 17, 2014, other Northwest utilities made further compliance filings in accordance with FERC's September 18, 2014 order. Bonneville has filed comments to the other Northwest Utilities' November 17, 2014 compliance filings to clarify how the Order 1000 planning agreement would operate for Bonneville and other non-jurisdictional participants that are not subject to mandatory cost allocation. 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.

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, as of September 2014, either the United States or Canada may elect to terminate it by providing not less than ten years' notice. No notice has been issued by either party.

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 cash payment obligations, including rental payments under the Lease-Purchase Agreement. 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.

Direction or Guidance from other Federal Agencies

Bonneville is part of the federal government. 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. In October 2014, Bonneville completed modifications to a redundant system control center (to incorporate an adjoining emergency scheduling center) that is geographically separated from the existing control center, one east and one west of the Cascade Mountains, in areas not subject to the same vulnerabilities. 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 implemented 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 287 megawatts of wind power will be integrated by the end of September 2015. 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 an 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 in the river 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 have been briefed. Oral argument has not been scheduled. 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 have been briefed and are stayed until January 2015. Bonneville and all parties with claims have agreed to settlement terms and expect to enter into settlement agreements by the end of December 2014. Under the proposed settlement, Bonneville would make payments of approximately $9 million, in aggregate, to wind generators and Regional IOUs. Bonneville will propose to recover the settlement costs in future rates on the same basis as oversupply costs under the Oversupply Management Protocol. See "—Oversupply Management Protocol."

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 through February 2, 2015.

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 that receive 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 filed 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. 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 proposed to allocate costs only to generators that are located within Bonneville's balancing authority area based on transmission use. In October 2014, FERC issued an order approving the OMP and the related cost allocation and rate, as amended by Bonneville.

In May 2013, various customers also petitioned the Ninth Circuit Court for direct judicial review of Bonneville's decision to renew the OMP and such cases are currently stayed through February 2, 2015.

From March 2012 to August 15, 2012, Bonneville displaced 49,654 megawatt hours of Fiscal Year 2012 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 on October 16, 2014 and expects to bill generators for such amounts in February 2015. Bonneville did not use OMP in Fiscal Year 2013 or 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, 2014, Bonneville had repaid $11.7 billion of principal of the Federal System investment and had approximately $3.7 billion principal amount outstanding with regard to such appropriated investments and $4.2 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 $12 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 $4.2 billion were outstanding as of the end of Fiscal Year 2014. 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 2014, the interest rates on the outstanding bonds ranged from .01 percent to 5.9 percent with a weighted average interest rate of approximately 3.1 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2014, Bonneville's outstanding bonds issued to the United States Treasury included $661 million in variable rate bonds at an average interest rate of 0.2 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, 2014, aggregate Non-Federal Debt outstanding was approximately $7.2 billion. By way of comparison, as of September 30, 2014, the principal amount of unrepaid appropriations for Federal System investments was approximately $4.1 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was $4.2 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 Energy Northwest Net Billed Projects represent the largest single component of Non-Federal Debt: $5.36 billion out of a total of $7.2 billion aggregate Non-Federal Debt, as of the end of Fiscal Year 2014.

As described in this section, under certain Net Billing Agreements, Bonneville has acquired indirectly from Energy Northwest the electric power capability of three large nuclear generating projects ("Energy Northwest Net Billed Projects"). Two of the projects ("Project 1" and "Project 3") were partially constructed before being terminated in the 1990s. The third project, the Columbia Generating Station, was completed and is operating. In May 2012, the Nuclear Regulatory Commission granted an operating license extension for Columbia Generating Station through calendar year 2043.

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 related 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.

Under the Net Billing Agreements, in payment for the share of the capability of each Energy Northwest 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 Energy Northwest Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's billing statement. Bonneville is obligated to pay this amount to such Participant by providing net billing credits against the amounts such Participant owes Bonneville under the Participant's power sales and other contracts with Bonneville and by making the cash payments described below. 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 Energy Northwest Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Energy Northwest Net Billed Project output or termination of the related Energy Northwest 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 amounts potentially subject to net billing are substantial. The debt service on the Net Billed Bonds in Fiscal Year 2014 was $344 million. In addition, Energy Northwest also incurs substantial operating expense for the Columbia Generating Station. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results and "POWER SERVICES—Description of the Generation Resources of the Federal System—Other Power Resources and Contract Purchases."

On October 29, 2014, three environmental advocacy organizations (the "Petitioners") filed a petition in Washington state court challenging a decision by the Washington Energy Facility Site Evaluation Council ("EFSEC") to issue a permit to Energy Northwest for wastewater discharges into and cooling water withdrawals from the Columbia River necessary for the operation of the Columbia Generating Station. The Columbia Generating Station has been operating under similar permits (each permit is typically in effect for a period of five years) since its operation commenced. The Petitioners allege, in effect, that the Columbia Generating Station cooling water intake system adversely affects Columbia River fish populations and that the issuance of the permit violates the federal Clean Water Act and related rules and regulations. The Petitioners seek, among other orders, an injunction vacating EFSEC's decision to authorize the permit, an injunction prohibiting EFSEC from authorizing the permit unless and until EFSEC modifies the permit provisions to comply with Petitioners' view of applicable law and regulation, and an order to remand the permit to EFSEC to modify its provisions to comply with Petitioners' view of applicable law and regulation. The Petitioners do not seek an order halting operation of Columbia Generating Station. Bonneville believes it is very unlikely that the court would instruct EFSEC to revoke the permit until any required modifications could be made because Columbia Generating Station has been operating under similar permits for decades with the same cooling water intake system and similar discharge levels. Bonneville believes that EFSEC's issuance of the permit will be upheld by the court; however, Bonneville can offer no assurance in this regard and it is possible that the litigation could result in additional cost to Energy Northwest to modify the cooling water intake and discharges. As described above, operating expenditures incurred by Energy Northwest for Columbia Generating Station are met by Bonneville. Also, see "—Direct Pay Agreements."

Bonneville's Transmission Facility Lease-Purchase Program

One type of Non-Federal Debt involves the entry by Bonneville into lease-purchase agreements 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 that the owner incurs or long-term bonds that 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 rental payments are not conditioned on the completion, suspension, or termination of the related facilities. Bonneville has entered into short-term and long-term lease-purchase arrangements with Northwest Infrastructure Financing Corporation and five affiliate corporations (collectively, the "NIFCs"), the Port of Morrow, and the Idaho Energy Resources Authority (the "IERA").

In Fiscal Year 2012, the Port of Morrow issued approximately $85 million in long-term, lease-purchase bonds having a final maturity of September 1, 2042. The Port of Morrow used the bond proceeds to acquire the related facilities from the prior owner of the facilities (Northwest Infrastructure Financing Corporation II), 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. In connection with the issuance of the Series 2014 Bonds, the Port of Morrow will use proceeds of the Series 2014 Bonds to acquire the Project from Northwest Infrastructure Financing Corporation III. See "—Bonneville's Capital Program— Possible Non-Federal Debt Activities in the Near Future."

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 $1.46 billion as of September 30, 2014. Of the foregoing amount, the aggregate outstanding principal amount of publicly-issued lease-purchase bonds was approximately $205 million.

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 2016. As of September 30, 2014, outstanding Non-Federal Debt associated with electric power prepayments was $319 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, 2014, outstanding Non-Federal Debt for generating resource acquisitions was $102 million, and outstanding Non-Federal Debt for electric power conservation resource acquisitions was $2 million.

The following table depicts the types and amounts of Non-Federal and Federal Debt outstanding as of the end of each of Fiscal Years 2012 through 2014.

Non-Federal and Federal Debt, Fiscal Years 2012-2014

Non-Federal and Federal Debt Outstanding

(Dollars in thousands)

Projects Financed with Non-Federal Debt	**2014**	**2013**	**2012**
Non-Federal Generation			
Columbia Generating Station	$3,304,805	$3,175,659	$3,224,040
Cowlitz Falls	85,055	87,995	104,650
Non-Federal Generation	3,389,860	3,263,654	3,328,690
Terminated Generation			
Nuclear Project No. 1	913,015	1,048,005	1,321,060
Nuclear Project No. 3	1,143,705	1,229,245	1,395,405
Terminated nuclear facilities	2,056,720	2,277,250	2,716,465
Terminated Northern Wasco Hydro Project	17,010	18,375	19,735
Sponsored Conservation			
Tacoma	1,790	3,495	5,120
Conservation and Renewable Energy System	--	3,004	5,870
Sponsored conservation	1,790	6,499	10,990
Lease-Purchase Program/Capital Leases	1,455,076	936,182	788,503
Customer prepaid power purchases	319,084	334,909	--
Total Non-Federal Debt	$7,239,540	$6,836,869	$6,864,383
Projects Financed with Federal Debt			
Federal Appropriations	4,090,050	4,291,457	4,246,022
Borrowings from U.S. Treasury	4,242,040	3,885,040	3,420,040
Total Federal Debt	$8,332,090	$8,176,497	$8,131,062
Total Debt	**$15,571,630**	**$15,013,366**	**$14,995,445**

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 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 or electric conservation billing credits, such obligations reduce the amount of cash available in the Bonneville Fund to meet Bonneville's cash payment obligations, including rental payments under the Lease-Purchase Agreement.

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 2010-2014. The following table reflects Bonneville's direct capital program only and excludes appropriated capital funding received by the Corps and Reclamation and capital investments associated with the Columbia Generating Station.

Historical Capital Spending by Program by Fiscal Year[1][2]
(Dollars in millions)

	2010	2011	2012	2013	2014	Total
Transmission	$470	$522	$557	$506	$613	**$2,668**
Federal System Hydro	148	200	214	206	173	**941**
Energy Efficiency[2]	58	162	80	78	78	**456**
Fish and Wildlife[2]	41	91	58	52	37	**279**
Facilities, Information Technology, Security	46	37	44	41	28	**196**
Total	**$763**	**$1,012**	**$953**	**$883**	**$929**	**$4,540**

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(1) Amounts include an Allowance for Funds Used during Construction ("AFUDC"), as applied in accordance with Bonneville's accounting policy as described in Appendix B (Financial Statement Note 1). AFUDC is a measure of interest on funds borrowed to construct electric utility plant to completion and operation.
(2) Amounts are classified as regulatory assets as described in Appendix B (Note 3 to Financial Statements).

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 2010 through Fiscal Year 2014. 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)

	2010	2011	2012	2013	2014	Total
Borrowing from United States Treasury	$604	$798	$664	$632	$544	**$3,242**
Lease-Purchases[2]	54	77	235	207	248	**821**
Projects Funded in Advance	105	107	39	9	7	**267**
Reserve Funding	-	30	15	15	15	**75**
Electric Power Prepayments[3]	-	-	-	20	115	**135**
Total	**$762**	**$1,012**	**$953**	**$883**	**$929**	**$4,539**

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(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 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)

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Transmission	$627	$530	$468	$399	$388	$372	$280	$286	$290	**$3,640**
Fed System Hydro	200	224	230	257	282	307	332	349	355	**2,537**
Energy Efficiency	92	95	98	101	104	107	110	113	116	**934**
Fish and Wildlife	52	55	31	19	35	35	34	29	29	**318**
Facilities, Information Technology, Security	89	100	67	61	58	53	59	52	54	**594**
AFUDC(1)	52	63	39	38	45	25	26	27	29	**345**
Total	**$1,112**	**$1,067**	**$933**	**$874**	**$912**	**$899**	**$841**	**$857**	**$874**	**$8,368**

(1) AFUDC applied in accordance with Bonneville's accounting policy as described in Appendix B (Note 1 to Financial Statements).

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 "—Possible Non-Federal Debt Activities in the Near Future." 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. As described in the Official Statement, the Issuer and NIFC III will enter into an agreement pursuant to which NIFC III will sell its interests in the NIFC III facilities to the Issuer. Concurrently, the Issuer and Bonneville will execute a lease-purchase agreement (the "Lease-Purchase Agreement") under which the Issuer will lease such facilities (the "Project") to Bonneville and pledge Bonneville's rental payments to the payment of debt service on the Series 2014 Bonds. The Issuer will use the proceeds from the sale of the Series 2014 Bonds to fund the acquisition of the transmission facilities from NIFC III. See the Official Statement under "INTRODUCTORY STATEMENT" and "PURPOSE OF ISSUANCE AND USE OF PROCEEDS." The Series 2014 Bonds will be secured solely by the Issuer's pledge of Bonneville's rental payments under the Lease-Purchase Agreement.

In calendar year 2015, Bonneville expects that the Issuer will issue about $400 million of Bonneville-supported lease-purchase bonds (federally taxable) to fund construction of certain facilities at Bonneville's Celilo Converter Station (see "—TRANSMISSION SERVICES—Bonneville's Federal Transmission System") and establish two Bonneville-supported $200 million short-term bank facilities to fund construction of $400 million of additional transmission facilities. In addition, Bonneville expects that the Issuer will issue about $100 million of Bonneville-supported bonds (federally taxable) to fund the acquisition by the Port of transmission facilities from Northwest Infrastructure Financing Corporation IV. The debt service of such bonds will be secured by Bonneville's rental payments under a long-term lease-purchase agreement. The Issuer has taken no official action to authorize such additional bonds or short-term bank loans.

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 that 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 Issuer, 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 otherwise collected through its rates, and Bonneville used these freed up revenues to pay down the principal balance of bonds outstanding to the United States Treasury and certain of Bonneville's appropriations repayment responsibilities. This had the effect of replenishing Bonneville's United States Treasury borrowing capacity for use to fund 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 certain of Bonneville's appropriations repayment responsibilities in the amount of approximately $2.5 billion, in aggregate.

In August 2014, Bonneville and Energy Northwest worked together in the issuance of Net Billed Bonds to extend the weighted average maturity of certain Net Billed Bonds. Under this regional cooperation debt transaction, the purpose was 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 Project 1 and Project 3, respectively. This freed up revenues that Bonneville had collected in its power rates and enabled Bonneville to prepay like amounts of its federal appropriations repayment obligations in Fiscal Year 2014. 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." Bonneville is also considering whether to initiate a billing credits program in which customers would fund electric power conservation activities and receive offsetting billing credits from Bonneville. Depending on the structure of the contracts, these transactions may be categorized as Non-Federal Debt, but such transactions would reduce the need for Bonneville to fund the related conservation measures from the proceeds of debt issued to the United States Treasury or from proceeds from Non-Federal Debt under the above-described conservation resource acquisition proposal. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Electric Power Conservation,"

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 $2 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 operations and maintenance expense to the Corps, Reclamation, and the Fish and Wildlife Service were $214.4 million, $114.3 million, and $27.6 million, respectively, in Fiscal Year 2014.

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 $642 million to $1.07 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 Bonneville 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 2014 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $991 million in Fiscal Year 2014, approximately $321 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 2015. 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 rental payments under the Lease-Purchase Agreement 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 rental payments under the Lease-Purchase Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2014 BONDS," and see "—Direct Pay Agreements" in this Appendix A.

Bonneville's operating revenues include amounts equal to net billing credits if and as provided by Bonneville under the Net Billing Agreements, see "—Bonneville's Non-Federal Debt—Energy Northwest Net Billed Projects Costs" and "—Direct Pay Agreements" above. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Energy Northwest Net Billing Agreements for the Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. (Bonneville and Energy Northwest have entered into 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 $37 million in Fiscal Year 2014 and will be $36 million in Fiscal Year 2015. In addition, Bonneville is considering whether to make available electric power conservation billing credits to Preference Customers. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Electric Power Conservation."

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 rental payments under the Lease-Purchase Agreement.

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 2014, approximately $606 million in Total Financial Reserves (cash, investments in United States Treasury market-based special securities and deferred borrowing) were derived from Power Services' rates and operations and $618 million in Total Financial Reserves were derived from Transmission Services' rates and operations.) "Total Financial Reserves" is an unaudited metric which is not in accordance with accounting principles generally accepted in the United States of America ("GAAP") 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." 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.

Regulation of these various financial instruments has substantially increased following the 2010 passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). Dodd-Frank 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. Rules regarding trading limits, and capital, reserve, and collateral requirements (primarily margin requirements) have been implemented.

In 2012, Bonneville's TRMC approved a permanent and ongoing financial hedging program using power futures that do not require physical delivery. 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 over-the-counter 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 (as presented in the table entitled, "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments," See "—Statement of Non-Federal Debt Service Coverage") 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.

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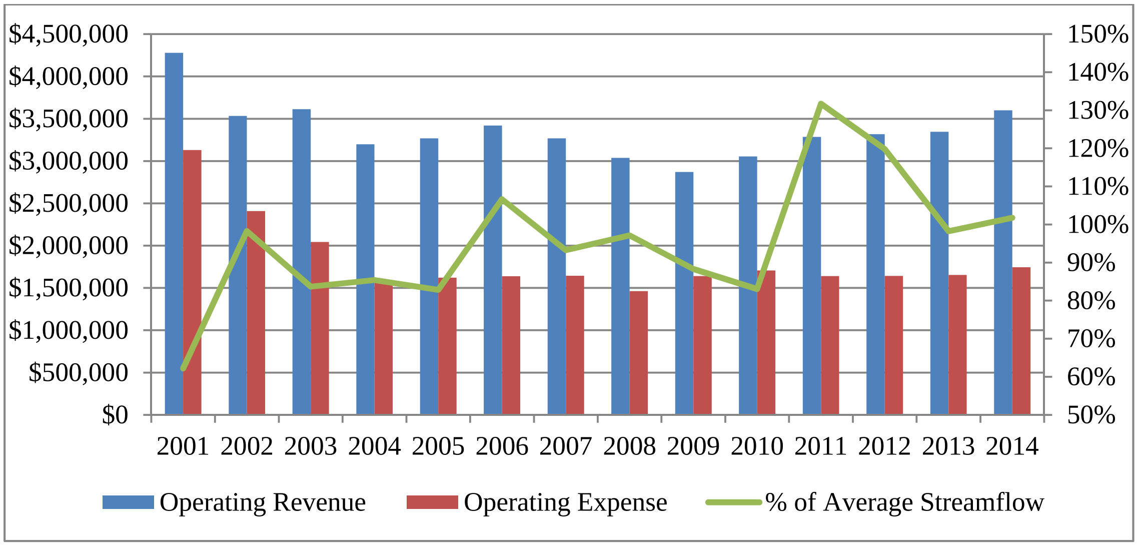
Historical Federal System Operating Revenue and Operating Expense
Compared to Historical Stream Flows
($ in thousands)



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 2012 through 2014 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 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	**2014**	**2013**	**2012**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities (1)	$1,945,139	$1,829,283	$1,833,277
Direct Service Industrial Customers	107,325	101,611	108,628
Northwest Investor-Owned Utilities	72,082	73,142	65,668
Sales outside the Northwest Region (2)	447,786	434,431	443,022
Book-outs (3)	(38,281)	(66,587)	(61,972)
Total Sales of Electric Power	2,534,051	2,371,880	2,388,623
Transmission (4)	931,671	857,696	821,232
Fish Credits and other Revenues (5)	134,624	116,705	107,995
Total Operating Revenues	3,600,346	3,346,281	3,317,850
Operating Expenses:			
Bonneville O&M (6)	1,014,889	960,622	965,419
Purchased Power (3)	199,056	154,173	143,119
Corps, Reclamation, and Fish & Wildlife O&M (7)	356,375	344,593	297,873
Non-Federal entities O&M — net billed (8)	292,476	297,485	283,745
Non-Federal entities O&M — non-net billed (9)	36,206	39,339	46,153
Total Operation and Maintenance	1,899,002	1,796,212	1,736,309
Net billed Debt Service	344,087	717,296	643,527
Non-net billed Debt Service	11,741	16,017	16,153
Non-Federal Projects Debt Service (10)	355,828	733,313	659,680
Federal Projects Depreciation	440,524	429,717	389,097
Residential Exchange (11)	201,342	201,933	203,712
Total Operating Expenses	2,896,696	3,161,175	2,988,798
Net Operating Revenues	703,650	185,106	329,052
Interest Expense:			
Appropriated Funds	235,766	236,805	232,364
Long-term debt	139,513	155,500	120,686
Capitalization Adjustment (12)	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(50,236)	(37,529)	(45,845)
Net Interest Expense (13)	260,138	289,871	242,300
Net Revenues/(Expenses)	$443,512	$(104,765)	$86,752
Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	10,197	9,994	10,819

(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. Refund amounts recorded in Fiscal Year 2014 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 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 $76.9 million, $84.1 million, and $103.8 million in Fiscal Years 2012, 2013, and 2014 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 2014, the Residential Exchange Program payments were $182.1 million. In Fiscal Year 2014, 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 2014

In Fiscal Year 2014, Bonneville made its scheduled United States Treasury payments on time and in full for the 31st consecutive year. Bonneville finished Fiscal Year 2014 with Total Financial Reserves of $1.22 billion, which is a decrease of approximately four percent from the prior fiscal year. See "—Bonneville's Financial Reserves."

In Fiscal Year 2014, Federal System net revenues (a GAAP-recognized metric) were $444 million, an improvement of approximately $548 million from net revenues of negative $105 million in Fiscal Year 2013. For additional details related to Fiscal Year 2014 Adjusted Net Revenues and Power Modified Net Revenues ("PMNR") (both non-GAAP metrics that remove the effects of certain debt management actions), see "—Bonneville's Use of Adjusted Net Revenues as a Financial Performance Metric."

For Fiscal Year 2014, Power Services and Transmission Services consolidated gross sales increased by approximately $223 million from the prior fiscal year. Power Services' gross sales increased $134 million, or approximately five percent, primarily due to two key factors: (i) firm power sales increased $118 million, or six percent, in Fiscal Year 2014 compared to Fiscal Year 2013 due to the nine percent average power rate increase which took effect beginning October 1, 2013 and higher Preference Customer peak loads due to colder than average temperatures in October 2013, December 2013 and February 2014; and (ii) seasonal surplus (secondary) sales increased $16 million in Fiscal Year 2014 compared to Fiscal Year 2013 due to slightly higher market prices and increased 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 2014 runoff volume at The Dalles Dam was 108 MAF. The full Fiscal Year 2014 volume finished at 135 MAF, an increase from 130 MAF in Fiscal Year 2013, and close to the historical average of 133 MAF.

Transmission Services gross sales increased $89 million, or 11 percent, mainly due to the 11 percent average transmission rate increase which took effect beginning October 1, 2013.

Transmission miscellaneous revenues decreased by $15 million, or 27 percent, mainly due to higher Fiscal Year 2013 reimbursable activity from other federal agencies for assistance Bonneville provided in the aftermath of Hurricane Sandy and the one-time receipt of revenues in Fiscal Year 2013 for 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 decreased approximately $264 million in Fiscal Year 2014 from Fiscal Year 2013. Operations and maintenance increased $57 million, or three percent, from the prior fiscal year primarily due to: (i) a $30 million increase in transmission maintenance and operation costs arising from increased reliability compliance activities, upgrades to Federal Transmission System communication systems, and additional labor costs for increased control center, substation, and transmission line maintenance, (ii) a $27 million increase in decommissioning expense due to the one-time only credit received in Fiscal Year 2013 for a settlement related to spent nuclear fuel storage costs at the terminated Trojan nuclear facility, (iii) a $26 million increase due to increased reliability compliance activities for Federal System hydroelectric projects, (iv) a $16 million increase in general and administrative costs related to support of information technology and infrastructure; and (v) a $6 million increase in renewable generation costs due to increased wind generation in Fiscal Year 2014. These increases were offset in part by a $32 million reduction in Columbia Generating Station costs due to higher costs in Fiscal Year 2013 related to the biennial refueling and higher maintenance costs. Bonneville also reduced spending on Fish and Wildlife program expenditures by $7 million, and power marketing and business support and transmission reimbursable programs by $9 million.

Purchased power expense increased $45 million, or 29 percent, from the prior fiscal year. The increase in purchased power was driven mainly by lower year-over-year hydroelectric generation (despite slightly increased streamflows) and reduced output of the Grand Coulee Dam due to reduced turbine capacity during scheduled renewal of certain facilities at the project in Fiscal Year 2014. Net interest expense for Fiscal Year 2014 decreased $30 million, or ten percent, compared to Fiscal Year 2013, primarily due to a non-cash gain on extinguishment of debt related to amounts borrowed from the United States Treasury, as further described in Appendix B (Note 7 to Financial Statements).

Non-Federal Projects Debt Service expense decreased $377 million, or 51 percent, from the prior fiscal year, primarily due to the debt management actions with respect to the issuance by Energy Northwest of the Energy Northwest Series 2014-C Bonds. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt."

Depreciation and amortization expense increased $11 million, or three percent, from the prior fiscal year, primarily due to increased completed plant in service for Power Services construction projects and for Transmission Services lease-purchased transmission facilities.

Bonneville's Use of Adjusted Net Revenues and Power Modified Net Revenues as Financial Performance Metrics. 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 non-operating effects on Bonneville of certain debt management actions with respect to the issuance by Energy Northwest of restructuring bonds in the 2000s (Debt Optimization, as described in "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program—Possible Non-Federal Debt Activities in the Near Future—Possible Additional Net Billed Bonds and Net Billed Project Debt Restructuring") 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.

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. 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 in Fiscal Year 2014 of the prior debt management actions were negative $170 million. 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 $236 million in Fiscal Year 2014, which was a $180 million increase from Bonneville's Adjusted Net Revenues of $56 million in Fiscal Year 2013. By contrast, as noted immediately above, net revenues were $444 million in Fiscal Year 2014.

In Fiscal Year 2014, Bonneville commenced utilizing and reporting a new non-GAAP financial metric for Power Services financial operations for determining Adjusted Net Revenues. This new metric (referred to as PMNR), seeks to eliminate the non-operating effects on Power Services of debt management actions with respect to the issuance of the Energy Northwest Series 2014-C Bonds under regional cooperation debt. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE —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.

In Fiscal Year 2014, Power Services had PMNR of $96 million and Transmission Services had Adjusted Net Revenues of $140 million.

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." 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 2014, RAR for Power Services operations was $273 million, an increase of 50 percent from the prior fiscal year, and RAR for Transmission Services operations was $511 million, an increase of 11 percent from the prior fiscal year. Aggregate Bonneville RAR was $784 million, an increase of 22 percent from the prior fiscal year. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Financial Reserves."

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—Electric Power Prepayments."

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; and (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.

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 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 (i) Reclamation costs increased by $38 million, primarily due to additional non-routine extraordinary maintenance work at Grand Coulee Dam, (ii) Columbia Generating Station costs increased $38 million because of biennial refueling and maintenance, (iii) transmission maintenance costs increased $11 million due to increased reliability compliance activities and upgrades to Federal Transmission System communication systems, and (iv) 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." 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 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.

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. 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.

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.

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

As of Sept. 30 – Dollars in thousands	**2014**	**2013**	**2012**
Total Operating Revenues	$3,600,346	$3,346,281	$3,317,850
Less: Operating Expenses[1]	1,743,969	1,653,552	1,642,148
Net Funds Available to meet Non-Federal Debt Service Obligations	1,856,377	1,692,729	1,675,702
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects[2]	355,828	733,313	659,680
Lease-Purchase Program[3]	38,979	28,949	25,451
Electric Power Prepayments [4]	30,600	12,750	-
Total Non-Federal Debt Service Obligations	425,407	775,012	685,131
Revenue Available for Treasury	1,430,970	917,717	990,571
Amount Allocated for Payment to Treasury[9]:			
Corps and Reclamation O&M[5]	356,375	344,593	297,873
Net Interest Expense[6]	260,138	289,871	242,300
Lease-Purchase Program[3]	(38,979)	(28,949)	(25,451)
Electric Power Prepayments[4]	(14,775)	(7,653)	-
Capitalization Adjustment[7]	64,905	64,905	64,905
Allowance for Funds Used During Construction [8]	20,913	15,058	28,175
Amortization of Federal Principal	567,061	224,540	393,110
Total Amount Allocated for Payment to Treasury[9]	1,215,638	902,365	1,000,912
Revenues Available for Other Purposes[10]	$215,333	$15,352	$(10,341)
Non-Federal Debt Service Coverage Ratio[11]	4.4x	2.2x	2.4x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[12]	1.7x	1.4x	1.4x

(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 $16.2 million, $16.8 million, and $11.7 million for Fiscal Years 2012, 2013, and 2014 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 2014, the aggregate debt service amount of $39.0 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 2014, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $30.6 million. Of this amount, $14.8 million is accounted for as Net Interest Expense and $15.8 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 2012, 2013, and 2014. 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 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 2012, 2013, and 2014 were $886 million, $692 million, and $991 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:

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

Bonneville's Financial Reserves

For cash management purposes, Bonneville tracks Total Financial Reserves (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), which are available to meet Bonneville's current expenditure needs. Total Financial Reserves is an unaudited metric which is not in accordance with GAAP that Bonneville uses to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations 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. 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 2014."

As of the end of Fiscal Year 2014, Bonneville had $784 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 "See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2014-2015."

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 2010-2014
($ 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
2014	1,224	784	750	317

(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. On July 9, 2014, the plaintiffs filed a seventh supplemental complaint in the Ninth Circuit Court. Briefing is scheduled to occur from December 2014 through April 2015. Oral argument is scheduled for June 23, 2015. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

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 took the position that no violation of the Appropriations Clause had occurred and there is no support for the proposition that Bonneville had an absolute duty to initiate collection efforts and pursue litigation against the DSIs for recovery of payments regardless of the circumstances. The matter was briefed and oral argument was held May 9, 2013. On September 18, 2014, the court issued its opinion denying in part and granting in part the petitions for review. In most respects, the court upheld Bonneville's decisions not to seek to recover funds from DSIs. The court directed Bonneville to reconsider Bonneville's decision not to seek to recover from Alcoa about $32 million in funds Bonneville paid to Alcoa under the amended agreement. The court also directed Bonneville to provide an adequate explanation of its decision upon reconsideration. Bonneville is initiating a process to comply with the court's order.

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 15.75 annual average megawatts and 300 annual average megawatts, respectively. The contracts end near the end of calendar year 2022.

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 2012-2013. In March 2013, certain petitioners filed litigation in the Ninth Circuit Court challenging certain decisions by Bonneville in the 2012 Rates ROD regarding 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 litigation involved whether certain purchase requirements power purchases would be served at Tier 1 PF Rates or at Tier 2 PF Rates. The amount of purchases at issue would not have exceeded 50 annual average megawatts. In response to certain motions for voluntary dismissal filed by the petitioners, the court has dismissed the litigation.

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. The parties await a decision by the court.

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 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 such findings (the "February 2013 Findings").

Following the issuance of the February 2013 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. The California Parties filed their response to Bonneville's brief. On November 10, 2014, FERC issued an order in which FERC did not accept the February 2013 Findings and instead dismissed Bonneville from the proceeding.

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. (This ruling is referred to herein as the City of Redding Opinion.) The Court of Federal Claims ruled that the Ninth Circuit Court's City of Redding 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 were 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 of the issuance by the Ninth Circuit Court of the City of Redding Opinion (described above), which concluded 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. At the judge's request, Bonneville thereafter filed a motion to dismiss the California Breach Claims. Thereafter, the plaintiffs filed with the judge (i) a motion seeking to reinstate the May 2012 CFC Order, and (ii) a motion requesting that the judge seek from the United States Court of Appeals for the Federal Circuit guidance as to whether it agrees with the interpretation of the City of Redding Opinion that the new judge intends to apply in the California Breach Claims case. The parties await the Court of Federal Claims judge's decisions on the motions.

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.

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APPENDIX B

FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS
FOR THE YEARS ENDED SEPTEMBER 30, 2014, 2013 AND 2012

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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, 2014 and 2013 and the related combined statements of revenue and expenses and cash flows for each of the three years in the period ended September 30, 2014.

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 entity's 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 entity'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 combined financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP, 805 SW Broadway, Suite 800, Portland, OR 97205-3344
T: (971) 544 4000, F: (971) 544 4100, www.pwc.com/us

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, 2014 and 2013 and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2014 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 30, 2014

Federal Columbia River Power System
Combined Balance Sheets

As of September 30

(Thousands of Dollars)

	2014	2013
Assets		
Utility plant		
Completed plant	**$ 16,618,215**	$ 16,153,536
Accumulated depreciation	**(5,941,078)**	(5,700,821)
	10,677,137	10,452,715
Construction work in progress	**1,603,811**	1,344,033
Net utility plant	**12,280,948**	11,796,748
Nonfederal generation	**3,361,386**	3,243,713
Current assets		
Cash and cash equivalents	**859,242**	1,010,128
Short-term investments in U.S. Treasury securities	**465,756**	388,914
Accounts receivable, net of allowance	**24,321**	29,540
Accrued unbilled revenues	**283,377**	260,757
Materials and supplies, at average cost	**112,445**	112,019
Prepaid expenses	**32,443**	40,458
Total current assets	**1,777,584**	1,841,816
Other assets		
Regulatory assets	**6,741,604**	6,953,397
Investments in U.S. Treasury securities	**94,542**	34,961
Nonfederal nuclear decommissioning trusts	**279,210**	254,752
Deferred charges and other	**396,876**	146,682
Total other assets	**7,512,232**	7,389,792
Total assets	**$ 24,932,150**	$ 24,272,069

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)

	2014	2013
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,823,085**	$ 2,432,217
Federal appropriations	**4,090,050**	4,291,457
Borrowings from U.S. Treasury	**3,944,040**	3,738,040
Nonfederal debt	**6,439,711**	6,229,004
Total capitalization and long-term liabilities	**17,296,886**	16,690,718
Commitments and contingencies (Note 14)		
Current liabilities		
Borrowings from U.S. Treasury	**298,000**	147,000
Nonfederal debt	**799,829**	607,865
Accounts payable and other	**555,165**	503,112
Total current liabilities	**1,652,994**	1,257,977
Other liabilities		
Regulatory liabilities	**2,322,386**	2,434,065
IOU exchange benefits	**2,795,470**	2,992,740
Asset retirement obligations	**176,127**	171,554
Deferred credits and other	**688,287**	725,015
Total other liabilities	**5,982,270**	6,323,374
Total capitalization and liabilities	**$ 24,932,150**	$ 24,272,069

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)

	2014	2013	2012
Operating revenues			
Sales	**$ 3,426,514**	$ 3,175,570	$ 3,179,592
U.S. Treasury credits for fish	**103,853**	84,092	76,983
Miscellaneous revenues	**69,979**	86,619	61,275
Total operating revenues	**3,600,346**	3,346,281	3,317,850
Operating expenses			
Operations and maintenance	**1,901,288**	1,843,972	1,796,902
Purchased power	**199,056**	154,173	143,119
Nonfederal projects	**355,828**	733,313	659,680
Depreciation and amortization	**440,524**	429,717	389,097
Total operating expenses	**2,896,696**	3,161,175	2,988,798
Net operating revenues	**703,650**	185,106	329,052
Interest expense and (income)			
Interest expense	**333,820**	356,337	331,732
Allowance for funds used during construction	**(50,236)**	(37,529)	(45,845)
Interest income	**(23,446)**	(28,937)	(43,587)
Net interest expense	**260,138**	289,871	242,300
Net revenues (expenses)	**443,512**	(104,765)	86,752
Accumulated net revenues at October 1	**2,432,217**	2,595,940	2,510,373
Irrigation assistance	**(52,644)**	(58,958)	(1,185)
Accumulated net revenues at September 30	**$ 2,823,085**	$ 2,432,217	$ 2,595,940

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)

	2014	2013	2012
Cash flows from operating activities			
Net revenues (expenses)	**$ 443,512**	$ (104,765)	$ 86,752
Non-cash items:			
Depreciation and amortization	**440,524**	429,717	389,097
Amortization of nonfederal projects	**119,168**	512,363	390,266
Gain on extinguishment of U.S. Treasury bonds	**(36,122)**	-	-
Changes in:			
Receivables and unbilled revenues	**(14,833)**	45,261	(7,564)
Materials and supplies	**(426)**	(12,583)	(5,512)
Prepaid expenses	**8,015**	(14,398)	3,370
Accounts payable and other	**35,636**	(53,511)	35,084
Regulatory assets and liabilities	**(95,454)**	(141,867)	(162,772)
IOU exchange benefits	**(197,270)**	(88,313)	(80,198)
Other assets and liabilities	**(5,148)**	(3,259)	(500)
Net cash provided by operating activities	**697,602**	568,645	648,023
Cash flows from investing activities			
Investment in utility plant, including AFUDC	**(842,983)**	(778,785)	(861,754)
U.S. Treasury securities:			
Purchases	**(950,001)**	(940,000)	(635,000)
Maturities	**808,429**	808,783	638,767
Deposits to nonfederal nuclear decommissioning trusts	**(3,234)**	(3,598)	(9,211)
Lease-purchase trust funds:			
Deposits to	**(519,039)**	(144,208)	(202,287)
Receipts from	**256,784**	160,095	231,994
Net cash used for investing activities	**(1,250,044)**	(897,713)	(837,491)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	**119,654**	99,175	104,696
Repayment	**(321,061)**	(56,740)	(164,594)
Borrowings from U.S. Treasury:			
Proceeds	**603,000**	632,000	806,000
Repayment	**(206,898)**	(167,800)	(328,600)
Nonfederal debt:			
Proceeds	**520,118**	488,965	202,289
Repayment	**(227,043)**	(498,748)	(364,388)
Customers:			
Net advances (refunds) for construction	**3,664**	(6,425)	27,634
Repayment of funds used for construction	**(37,234)**	(41,132)	(35,650)
Irrigation assistance	**(52,644)**	(58,958)	(1,185)
Net cash provided by financing activities	**401,556**	390,337	246,202
Net (decrease) increase in cash and cash equivalents	**(150,886)**	61,269	56,734
Cash and cash equivalents at beginning of year	**1,010,128**	948,859	892,125
Cash and cash equivalents at end of year	**$ 859,242**	$ 1,010,128	$ 948,859
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 350,743**	$ 377,167	$ 350,581
Significant noncash investing and financing activities:			
U.S Treasury bonds repaid with non-cash gains	**$ (39,102)**	$ -	$ -
Federal appropriations	**$ -**	$ -	$ (40,583)
Nonfederal debt increase for Energy Northwest	**$ 221,550**	$ 12,639	$ 782,655
Nonfederal debt extinguished through refinancing for Energy Northwest	**$ (111,954)**	$ (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, 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 (USoA) 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 based on BPA statutes that 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. BPA's rates are not structured to provide a rate of return on its assets.

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.)

Utility plant

Utility plant is stated at original cost and includes generation and transmission assets. Generation assets were $8.62 billion and $8.43 billion at Sept. 30, 2014, and 2013, respectively. Transmission assets were $7.99 billion and $7.72 billion, including assets under capital lease agreements of $150.7 million and $127.7 million, at Sept. 30, 2014, and 2013, 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 (AFUDC). 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 utility plant is retired, the original cost and any net proceeds from the disposition are charged to accumulated depreciation.

Depreciation and amortization

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.

Amortization expense relates primarily to certain regulatory assets. (See Note 3, Effects of Regulation.)

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.

AFUDC is capitalized 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 for the Lease-Purchase Program. The respective rates for appropriated and BPA funds were approximately 0.1 percent and 3.7 percent in fiscal year 2014, 0.1 percent and 3.6 percent in fiscal year 2013, and 0.1 percent and 4.1 percent in fiscal year 2012.

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. These contracts require BPA to meet all of the facilities' operating, maintenance and debt service costs. Operations and maintenance and debt service expenses for these projects are recognized 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, with the amortization expense included in Nonfederal projects on the Combined Statements of Revenues and Expenses. (See Note 8, Nonfederal Financing.)

Cash and cash equivalents

Cash amounts include cash in the Bonneville Power Administration Fund (Bonneville Fund) with the U.S. Treasury and unexpended appropriations of the Corps and Reclamation. Cash equivalents consist of investments in non-marketable market-based special securities issued by the U.S. Treasury (market-based specials) 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, and 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 2014, 2013 and 2012, 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

Derivative instruments are measured at fair value and recognized 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 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. The FCRPS does not apply hedge accounting.

Fair value

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, fair value measurements are used to record adjustments to certain financial assets and liabilities and to determine fair value disclosures. When developing fair value measurements, it is FCRPS 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. Net revenues over time are committed to payment of operational obligations, including debt for both operating and nonoperating nonfederal projects, debt service on bonds BPA issues to the U.S. Treasury, the repayment of federal appropriations in the FCRPS, and the payment of certain irrigation costs.

U.S. Treasury credits for fish

Under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), BPA makes expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes. 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 federal 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.

Nonfederal projects

Nonfederal projects expense represents the amortization of nonfederal generation assets and regulatory assets for terminated nonfederal nuclear and hydro facilities, as well as the interest expense on the debt related to those assets. This expense is recognized over the terms of the related outstanding debt.

Interest expense

Interest expense includes interest associated with the balance of federal appropriations for investments in the FCRPS, interest on bonds issued by BPA to the U.S. Treasury, and interest on certain nonfederal debt. Reductions to interest expense include the amortization of a capitalization adjustment regulatory liability and also gains related to the repayment of certain U.S. Treasury bonds considered extinguished or modified after being called and reissued. Interest expense excludes interest on certain nonfederal debt that is instead reported as a component of nonfederal projects expense.

Interest income

Interest income includes earnings on balances in the Bonneville Fund including market-based specials and from other sources. BPA continues to earn interest offset credits on certain cash balances in the Fund that are not invested in market-based specials. These credits reduce some interest payments, associated with federally appropriated investments in the FCRPS, in the amount of the interest earned. The interest offset credits are earned at the weighted-average interest rate of BPA's outstanding U.S. Treasury borrowings. Interest earnings on U.S. Treasury market-based special investments are based on the stated rates of the individual securities.

Residential Exchange Program

In order to provide qualifying regional utilities, primarily IOUs, access to power 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.

In fiscal year 2011, the BPA administrator signed the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement), resolving disputes related to the REP. The 2012 REP Settlement Agreement provides for fixed "Scheduled Amounts" payable to the IOUs, as well as fixed "Refund Amounts" payable to the COUs. The Refund Amounts do not reduce rates but are reflected as credits to qualifying COUs' bills as designated in the 2012 REP Settlement Agreement. (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, FCRPS does not record any accumulated plan assets or liabilities related to the administration of such programs. Contribution amounts are paid to the U.S. Treasury and are recorded as expense during the year to which the payment relates.

RECENT ACCOUNTING PRONOUNCEMENTS

Balance Sheet Offsetting

In January 2013, the Financial Accounting Standards Board (FASB) issued authoritative guidance that clarifies the scope of disclosure about offsetting assets and liabilities that are presented on a net or gross basis in the Combined Balance Sheets. The guidance requires additional qualitative and quantitative disclosures about financial instruments and derivative instruments subject to an enforceable master netting agreement or similar agreement. FCRPS adopted this guidance on October 1, 2013. This guidance enhanced disclosures in the notes to financial statements with no impact to BPA's financial condition, results of operations or cash flows.

Revenue Recognition

In May 2014, the FASB issued authoritative guidance that supersedes the existing revenue recognition guidance, including most industry-specific guidance. Management is evaluating the impact of adopting this guidance, which will be effective for fiscal year 2018.

SUBSEQUENT EVENTS

Management has performed an evaluation of events and transactions for potential FCRPS recognition or disclosure through Oct. 30, 2014, which is the date the financial statements were issued.

2. Investments in U.S. Treasury Securities

As of Sept. 30 — thousands of dollars	**2014**		2013	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Short-term	**$ 465,756**	**$ 465,821**	$ 388,914	$ 389,127
Long-term	**94,542**	**94,693**	34,961	34,972
Total	**$ 560,298**	**$ 560,514**	$ 423,875	$ 424,099

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 market-based specials. Under its banking arrangement with the U.S. Treasury, BPA has agreed to invest at least $100 million annually in market-based specials, thereby increasing the amounts of market-based specials in the Bonneville Fund. At the earlier of the date that the Bonneville Fund is fully invested or Sept. 30, 2018, all balances in the Bonneville Fund will thereafter be invested through the Federal Investment Program.

Market-based specials held during fiscal years 2014 and 2013 had a weighted-average yield of 0.2 percent and 0.3 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, FCRPS 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 occurring in October 2015 and beyond.

3. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars	**2014**	2013
REP Scheduled Amounts	**$ 2,795,470**	$ 2,903,634
Terminated nuclear facilities	**2,031,329**	2,154,900
Columbia River Fish Mitigation	**656,677**	600,413
REP Refund Amounts	**364,208**	432,850
Conservation measures	**340,854**	319,082
Fish and wildlife measures	**309,607**	302,245
Legal claims and settlements	**91,755**	76,601
Spacer damper replacement program	**50,006**	46,563
Federal Employees' Compensation Act	**32,558**	32,558
Trojan decommissioning and site restoration	**24,039**	24,431
Derivative instruments	**16,304**	27,108
Terminated hydro facilities	**15,860**	17,238
Other	**12,937**	15,774
Total	**$ 6,741,604**	$ 6,953,397

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 in rates through 2028. These amounts amortize to operations and maintenance expense. (See Note 10, Residential Exchange Program.)

"Terminated nuclear facilities" consist of the nonfederal debt for Energy Northwest Nuclear Projects 1 and 3. These assets are amortized to nonfederal projects expense 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 in rates over 75 years and amortized to depreciation and amortization expense.

"REP Refund Amounts" are amounts that reduce the REP benefit payments through fiscal year 2019 and were established in the 2012 REP Settlement Agreement. (See Note 10, Residential Exchange Program.) These amounts are recoverable in future rates and are equal to the regulatory liability for REP Refund Amounts to COUs.

"Conservation measures" consist of the costs of deferred conservation measures and are amortized to depreciation and amortization expense over periods from five to 20 years.

"Fish and wildlife measures" consist of deferred fish and wildlife project expenses and are amortized to depreciation and amortization expense 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 to operations and maintenance expense through future rates over a period established by the administrator.

"Spacer damper replacement program" consists of costs to replace deteriorated spacer dampers and are recovered in rates under the Spacer Damper Replacement Program. These costs are amortized to depreciation and amortization expense over a period of 25 or 30 years.

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

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

"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 and equal the associated liability.

"Terminated hydro facilities" consist of the nonfederal debt for the terminated Northern Wasco hydro project, for which BPA terminated its participation. These assets are amortized to nonfederal projects expense over the term of the related outstanding debt. (See Note 8, Nonfederal Financing.)

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars	**2014**	2013
Capitalization adjustment	**$ 1,407,081**	$ 1,471,986
Accumulated plant removal costs	**410,532**	408,218
REP Refund Amounts to COUs	**364,208**	432,850
Decommissioning and site restoration	**129,414**	109,819
Other	**11,151**	11,192
Total	**$ 2,322,386**	$ 2,434,065

Regulatory liabilities include the following items:

"Capitalization adjustment" is the difference between appropriated debt before and after refinancing under 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 original 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 as a reduction to interest expense was $64.9 million for fiscal years 2014, 2013 and 2012, respectively. (See Note 6, Federal Appropriations.)

"Accumulated plant removal costs" are the amounts previously collected through rates as part of depreciation. The liability will be reduced as actual removal costs are incurred. (See Note 1, Summary of Significant Accounting Policies.)

"REP Refund Amounts to COUs" are the amounts previously collected through rates that are owed to qualifying consumer-owned utilities and will be provided as credits on their future bills through 2019 as established in the 2012 REP Settlement Agreement. These amounts are equal to regulatory assets for REP Refund Amounts. (See Note 10, Residential Exchange Program.)

"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 Energy Northwest Projects 1 and 4 sites. (See Note 4, Asset Retirement Obligations.)

4. Asset Retirement Obligations

As of Sept. 30 — thousands of dollars	**2014**	2013
Beginning Balance	**$ 171,554**	$ 161,215
Activities:		
Accretion	**8,390**	8,507
Expenditures	**(1,601)**	(596)
Revisions	**(2,216)**	2,428
Ending Balance	**$ 176,127**	$ 171,554

AROs are recognized 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. The FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO because no obligation exists to remove these assets.

AROs include the following items as of Sept. 30, 2014:

- CGS decommissioning and site restoration of $135.5 million;
- Trojan decommissioning of $24.0 million;
- Energy Northwest Projects 1 and 4 site restoration of $16.6 million.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — thousands of dollars	**2014**		2013	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Equity index funds	**$ 85,550**	**$ 121,088**	$ 87,723	$ 117,212
U.S. government obligation mutual funds	**93,537**	**93,329**	77,022	76,801
Corporate bond index funds	**61,888**	**64,789**	59,402	60,726
Cash and cash equivalents	**4**	**4**	13	13
Total	**$ 240,979**	**$ 279,210**	$ 224,160	$ 254,752

These assets represent trust fund balances for decommissioning and site restoration costs. External trust funds for decommissioning and site restoration costs are funded monthly for CGS and are charged to operations and maintenance. The trust funds are expected to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this period be no longer than 60 years from the time the plant ceases operations. In May 2012, the NRC renewed CGS's operating license for an additional 20 years, with the license now expiring 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 as available-for-sale and recorded at fair value in accordance with accounting guidance related to Investments, Debt and Equity Securities. Unrealized gains and losses on these investment securities are recognized 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.)

Contribution payments to the CGS trusts for fiscal years 2014, 2013 and 2012 were approximately $3.2 million, $3.6 million and $9.2 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. BPA and Energy Northwest have no obligation to make further payments into the site restoration fund for Energy Northwest Projects 1 and 4.

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	**2014**	2013
Lease-Purchase trust funds	**$ 355,370**	$ 99,623
Settlements receivable	**16,000**	16,000
Spectrum Relocation fund	**8,290**	8,307
Funding agreements	**7,174**	7,174
Derivative instruments	**4,772**	4,814
Other	**5,270**	10,764
Total	**$ 396,876**	$ 146,682

Deferred Charges and Other include the following items:

"Lease-Purchase trust funds" are amounts held in separate trust accounts outside the Bonneville Fund for the construction of leased transmission assets, the use of which BPA has received under lease-purchase agreements. The amounts held in trust are also used in part for debt service payments during the construction period and include an investment fund mainly for future principal and interest debt service payments. (See Note 8, Nonfederal Financing.) These trust balances consist of cash and cash equivalents and investments classified as either trading or held to maturity. Trading securities, which comprise the majority of trust balances, are held for construction purposes and are stated at fair value based on quoted market prices. Interest income and realized and unrealized gains or losses on amounts held in trust for construction are recorded as AFUDC. Interest income and gains and losses on other trust balances are recorded as either income or expense in the period when earned.

"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 certain federal agencies such as BPA for 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 Bonneville Fund for the sole purpose of constructing replacement assets.

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

"Derivative instruments" represent unrealized gains from BPA's derivative portfolio, which includes physical power purchase and sale transactions and power exchange transactions.

6. Federal Appropriations

Federal 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 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 repayment balance 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 original period of repayment. (See Note 3, Effects of Regulation.)

Appropriations for federal generation and transmission plant investments are repaid to the U.S. Treasury within a specified repayment period, which is the reasonable expected service life of the facility, not to exceed 50 years. Federal appropriations may be paid early without penalty. All outstanding federal appropriations are due in fiscal year 2019 and thereafter.

The weighted-average interest rate was 5.9 percent and 6.1 percent on outstanding appropriations as of Sept. 30, 2014, and 2013, respectively.

7. Borrowings from U.S. Treasury

BPA is authorized by Congress to issue and sell to the U.S. Treasury, and have outstanding at any one time, up to $7.70 billion aggregate principal amount of bonds. Of the $7.70 billion in U.S. 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 BPA's transmission capital program and to implement BPA's authorities under the Northwest Power Act. Of the $7.70 billion, $750 million can be issued to finance Northwest Power Act related expenses. The interest on BPA's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. Bonds can be issued with call options.

As of Sept. 30, 2014, of the total $4.24 billion of outstanding balance, none related to Northwest Power Act expenses. Outstanding bonds carrying a variable rate of interest were $661.0 million and $300.0 million at Sept. 30, 2014, and 2013, respectively. 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 $416.9 million and $297.2 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2014, and 2013, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 3.1 percent and 3.8 percent as of Sept. 30, 2014, and 2013, respectively. As of Sept. 30, 2014, the outstanding bonds with a variable rate of interest carried an interest rate of 0.2 percent.

Of the outstanding U.S. Treasury borrowings, $218.8 million is not subject to redemption prior to their stated maturities. As of Sept. 30, 2014, $661.0 million are callable by BPA at par value and the remaining $3.36 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.

During fiscal year 2014, BPA called $1.18 billion principal amount of previously issued U.S. Treasury borrowings prior to maturity and reissued $1.14 billion principal amount of shorter-duration debt at lower interest rates. The result of these noncash transactions was a gain of $36.4 million for extinguished debt, which decreased interest expense immediately, as well as a gain of $3.4 million for modified debt, which is amortized to interest expense over the term of the new debt.

MATURING BORROWINGS FROM U.S. TREASURY

As of Sept. 30 — thousands of dollars	
2015	$ 298,000
2016	30,000
2017	68,400
2018	9,000
2019	574,940
2020 through 2044	3,261,700
Total	**$ 4,242,040**

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars		**2014**		2013	
	Terms	**Recorded Value**	Weighted Average Interest Rate	Recorded Value	Weighted Average Interest Rate
Nonfederal generation:					
Columbia Generating Station	0.3 – 6.8% through 2044	**$ 3,304,805**	4.2%	$ 3,175,659	4.3 %
Cowlitz Falls	2.0 – 5.3% through 2032	**85,055**	5.1	87,995	5.0
Terminated nonfederal generation:					
Nuclear Project 1	1.3 – 7.1% through 2027	**913,015**	5.0	1,048,005	5.0
Nuclear Project 3	1.3 – 7.1% through 2028	**1,143,705**	4.9	1,229,245	5.0
Northern Wasco Hydro Project	1.0 – 5.0% through 2024	**17,010**	3.3	18,375	3.1
Lease-Purchase Program:					
Consolidated NIFC debt	1.8 – 5.4% through 2034	**734,783**	3.4	713,018	3.5
Capital leases	1.9 – 6.1% through 2042	**686,795**	2.8	188,443	3.1
Other capital leases	5.3 – 7.4% through 2044	**33,498**	6.8	34,721	6.7
Customer prepaid power purchases	4.3 – 4.6% through 2028	**319,084**	4.5	334,909	4.5
Other	2.0 – 5.0% through 2015	**1,790**	4.6	6,499	4.6
Total		**$ 7,239,540**		$ 6,836,869	

Nonfederal generation and Terminated nonfederal generation

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 meet 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 1 and 70 percent of Energy Northwest’s Nuclear Project 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 terminated nuclear projects. BPA is also required by a “Settlement and Termination Agreement” between BPA and Northern Wasco PUD to pay amounts equal to annual debt service on the Northern Wasco Hydro Project under which BPA ceased its participation.

BPA recognizes expenses for these nonfederal generation and terminated nuclear generation 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 $301.1 million, $307.3 million and $298.3 million in fiscal years 2014, 2013 and 2012, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service expense for all projects of $355.8 million, $733.3 million and $659.7 million for fiscal years 2014, 2013 and 2012, respectively, is reported as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

During fiscal year 2014, Energy Northwest took debt management actions for terminated Projects 1 and 3, which reduced debt service and amortization of the related regulatory assets in fiscal year 2014 by $378.1 million from rate case estimates. As a result of these debt management actions, amounts otherwise collected in BPA's Power rates were not used to fund the Energy Northwest related principal payments as originally intended, and as included in rates, and were instead used to repay, before their maturity date, $320.6 million of higher interest rate federal appropriations during fiscal year 2014.

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

The underlying debt for the Energy Northwest obligations currently matures through 2044. Energy Northwest debt of $1.27 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2015 and July 2024 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded recorded value by $591.2 million and $510.7 million as of Sept. 30, 2014, and 2013, 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.

Lease-Purchase Program and Other capital leases

Under the Lease-Purchase Program, BPA consolidates five special purpose corporations, collectively referred to as Northwest Infrastructure Financing Corporations (NIFCs), which issued debt to and received advances from nonfederal sources. The combined NIFCs have issued $119.6 million in bonds and borrowed $615.2 million on lines of credit with various banks as of Sept. 30, 2014. 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 April 1, 2015, and Jan. 1, 2019.

The fair value of the combined NIFC bonds and lines of credit, reported as capital leases, exceeded the recorded value by $23.6 million and $30.2 million as of Sept. 30, 2014, and 2013, 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, 2014, and 2013, respectively.

Lease-purchases with entities that are not consolidated in the combined FCRPS financial statements are reported as capital leases. These include BPA's lease-purchases with the Port of Morrow, a port district located in Morrow County, Oregon, and Idaho Energy Resources Authority (IERA) for transmission facilities, including lines, substations and general plant assets.

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

Completed plant assets under capital lease agreements were $150.7 million and $127.7 million, and the accumulated depreciation was $22.7 million and $19.3 million, at Sept. 30, 2014, and 2013, respectively. The capital leases expire on various dates through 2044. Generally the capital lease agreements contain provisions that allow BPA to purchase the related assets at any time 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.

Customer prepaid power purchases

During fiscal year 2013, BPA entered into agreements with four regional COUs for the advance payment of customer power purchases. Under this program, customers purchased prepaid power in blocks through fiscal year 2028. For each block purchased, BPA repays the prepayment, with interest, as 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 through fiscal year 2028.

As of Sept. 30 — thousands of dollars	MATURING NONFEDERAL DEBT EXCLUDING CAPITAL LEASES	FUTURE MINIMUM LEASE PAYMENTS UNDER CAPITAL LEASES	TOTAL
2015	$ 798,601	$ 24,408	$ 823,009
2016	817,904	24,343	842,247
2017	592,296	24,263	616,559
2018	929,292	24,243	953,535
2019	636,156	23,928	660,084
2020 and thereafter	2,744,998	856,079	3,601,077
Total	$ 6,519,247	$ 977,264	$ 7,496,511
Less: Executory costs	—	30,441	30,441
Less: Amount representing interest	—	226,530	226,530
Present value of Nonfederal debt	**6,519,247**	**720,293**	**7,239,540**
Less: Current portion	798,601	1,228	799,829
Long-term Nonfederal debt	$ 5,720,646	$ 719,065	$ 6,439,711

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.

Management 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. Management 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.

Management also reviews executed lease-purchase agreements with certain nonfederal entities. These entities, including the Port of Morrow and IERA, are governmental and therefore do not qualify for consolidation into the FCRPS financial statements according to VIE accounting guidance. However, 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-purchase agreements. Additionally, BPA's lease-purchase 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, the full use of which is then provided to BPA. The collateral for the debt is the lease rental 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 NIFC entities for all construction and operating risks associated with their respective 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.

Amounts related to the NIFC entities include Lease-Purchase trust funds and other assets of $25.5 million and $27.0 million and Nonfederal debt of $734.8 million and $713.0 million as of Sept. 30, 2014, and 2013, respectively.

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. The REP has been the subject of numerous settlement agreements and has been litigated at many stages of its implementation.

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 accumulated to $89.4 million by the end of December 2013; 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, were resolved. In fiscal year 2014, the conditions allowing for payment were met, and BPA paid all remaining Interim Agreement true up payments. (See Note 14, Commitments and Contingencies.)

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 REP Settlement Agreement).

In July 2011, the BPA administrator signed the REP-12 Final ROD and the 2012 REP Settlement Agreement, and BPA recorded an associated long-term IOU exchange benefits liability and corresponding regulatory asset of $3.07 billion. Beginning in fiscal year 2012, under the provisions of the 2012 REP 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 REP Settlement Agreement that relies upon each 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, with remaining payments as of Sept. 30, 2014, totaling $3.50 billion. Amounts recorded of $2.80 billion at Sept. 30, 2014, represent the present value of future cash outflows for these exchange benefits.

REP SCHEDULED AMOUNTS

As of Sept. 30 — thousands of dollars	
2015	$ 197,500
2016	214,100
2017	214,100
2018	232,200
2019	232,200
2020 through 2028	2,413,900
Total	**$ 3,504,000**

In addition to Scheduled Amounts, the 2012 REP 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 were established as a regulatory asset and regulatory liability for the refunds that will be provided to BPA customers as credits on customer monthly bills. The 2012 REP Settlement Agreement established Refund Amounts totaling $612.3 million, with remaining refunds as of Sept. 30, 2014, totaling $382.7 million. Amounts recorded as a regulatory liability of $364.2 million at Sept. 30, 2014, represent the present value of future cash flows for the amounts to be refunded to COUs and collected from IOUs.

11. Deferred Credits and Other

As of Sept. 30 — thousands of dollars	**2014**	2013
Customer reimbursable projects	**$ 220,165**	$ 227,120
Generation interconnection agreements	**196,183**	219,510
Third AC Intertie capacity agreements	**101,323**	104,406
Legal claims and settlements	**89,019**	82,580
Federal Employees' Compensation Act	**32,558**	32,558
Fiber optic leasing fees	**24,821**	27,004
Derivative instruments	**16,304**	27,108
Other	**7,914**	4,729
Total	**$ 688,287**	$ 725,015

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 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.

"Fiber optic leasing fees" reflect unearned revenue related to the leasing of fiber optic cables. Revenue is recognized over the lease terms extending through 2024.

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

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 2014, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2014, BPA had $28.2 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.

INTEREST RATE RISK

BPA has the ability to issue variable rate bonds or related instruments to the U.S. Treasury. BPA manages the interest rate risk presented by variable rate U.S. Treasury debt by holding a like 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 are delivered and settled.

For derivative instruments not eligible for the normal purchases and normal sales exception, BPA records unrealized gains and losses 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 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, 2014, the derivative commodity contracts recorded at fair value totaled 3.1 million MWh (gross basis) with delivery months extending to September 2019.

BPA has elected in the Combined Balance Sheets to report gross fair value amounts of derivative instruments subject to a master netting arrangement, excluding contracts designated as normal purchases or normal sales. In the event of default or termination, contracts with the same counterparty are offset and net settle through a single payment. BPA does not offset cash collateral against recognized derivative instruments with the same counterparty under the master netting arrangements.

If netted by counterparty, BPA's derivative position would result in a liability of $16.1 million as of Sept. 30, 2014. As of Sept. 30, 2013, BPA's derivative position resulted in a net asset of $0.1 million and a net liability of $27.1 million in other assets and other liabilities, respectively.

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, corporate and municipal securities as part of the Lease-Purchase 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-Purchase 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 adjusted market prices from an active market, plus an adder.

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, 2014, and 2013.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2014 — thousands of dollars

	Level 1	Level 2	Level 3	Netting[2]	Total
Assets					
Nonfederal nuclear decommissioning trusts					
Equity index funds	$ 121,088	$ —	$ —	$ —	**$ 121,088**
U.S. government obligation mutual funds	93,329	—	—	—	**93,329**
Corporate bond index funds	64,789	—	—	—	**64,789**
Cash and cash equivalents	4	—	—	—	**4**
Derivative instruments [1]					
Commodity contracts	—	227	4,545	—	**4,772**
Lease-Purchase trust funds					
U.S. government sponsored enterprise obligations	—	168,296	—	—	**168,296**
U.S. government obligations	—	92,759	—	—	**92,759**
Corporate obligations	—	27,274	—	—	**27,274**
Municipal obligations	—	30,882	—	—	**30,882**
Total	$ 279,210	$319,438	$ 4,545	$ —	**$ 603,193**
Liabilities					
Derivative instruments [1]					
Commodity contracts	$ —	$(16,304)	$ —	$ —	**$ (16,304)**
Total	$ —	$(16,304)	$ —	$ —	**$ (16,304)**

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-Purchase 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)

[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 $4.5 million at Sept. 30, 2014. The volumes under these contracts will be physically delivered in various quantities through April 2016.

As of Sept. 30, 2014, 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	$33.90	$47.85	$41.64
Off-Peak	$21.10	$41.20	$35.11

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	**2014**	2013
Beginning Balance	**$ 4,747**	$ 13,966
Changes in unrealized gains (losses)[1]	**(202)**	(9,219)
Ending Balance	**$ 4,545**	$ 4,747

[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 that BPA has entered into is $709.8 million as of Sept. 30, 2014. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — thousands of dollars		
2015	$	52,204
2016		61,066
2017		51,482
2018		27,612
2019		57,317
2020 through 2045		305,206
Total	**$**	**554,887**

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 $554.9 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 the cost of which BPA has no obligation to repay.

FIRM PURCHASE POWER COMMITMENTS

As of Sept. 30 — thousands of dollars		
2015	$	24,656
2016		32,337
2017		70,446
2018		74,834
2019		77,563
2020 and 2021		77,580
Total	**$**	**357,416**

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 preceding 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 10 purchases made specifically to meet BPA’s commitments to sell power at Tier 2 rates in fiscal years 2015-2019 and two purchases to meet load obligations in Idaho. The expenses associated with Tier 2 purchases were $4.9 million, $23.4 million and $8.5 million for fiscal years 2014, 2013 and 2012, respectively. Idaho purchases do not commence until July 1, 2016, and extend through fiscal year 2021. BPA has several power purchase agreements with wind-powered and other generating facilities that are not included in the preceding table as payments are based on the variable amount of future energy generated and as there are no minimum payments required.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Northwest Power 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. 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 conservation commitments made by BPA to its customers. These commitments are captured through $107.9 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 2017.

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 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 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 $17.2 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $6.8 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 $121.3 million limited to an annual maximum of $18.9 million. Assessments would be included in BPA’s costs and recovered through rates. As of Sept. 30, 2014, there have been no assessments to BPA under either of these programs.

ENVIRONMENTAL MATTERS

From time to time there are sites for which BPA, the 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.

INDEMNIFICATION AGREEMENTS

BPA has provided indemnifications of varying scope and terms in contracts with customers, vendors, lessors, trustees, and other parties with respect to certain matters, including, but not limited to, losses arising out of particular actions taken on behalf of BPA, electrical disturbances on specific projects, certain circumstances related to Energy Northwest Projects, and in connection with lease-purchases. Because of the absence of a maximum obligation in the provisions, management is not able to reasonably estimate the overall maximum potential future payments. Based on historical experience and current evaluation of circumstances, management believes that, as of September 30, 2014, the likelihood is remote that BPA would incur any significant costs with respect to such indemnities. No liability has been recorded in the financial statements with respect to these indemnification provisions.

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 $33.1 million, including interest, 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. 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, 2014, could approximate up to $55.9 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 law 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. Management 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 new judge for the Court of Federal Claims was assigned to the claims, and on December 20, 2013, she vacated the May 2012 ruling that BPA breached its contracts with California parties. The judge conducted a hearing on June 5, 2014, for the parties to show cause why the court, on reconsideration, should not dismiss the 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 claims. BPA filed a motion to dismiss plaintiffs’ claims for breach of contract on July 1, 2014. BPA is awaiting a decision on the motion to dismiss. The plaintiffs will have the opportunity to appeal if the cases are dismissed by the Court of Federal Claims. Management will reassess the probability of financial loss after the judge issues a ruling on the plaintiffs’ standing and the court’s jurisdiction over the claims, and will take into consideration the prospects of the matter on appeal, if appeals are filed.

BPA has not adjusted its liability for the California parties’ refund claims as a result of the events occurring at the Court of Federal Claims during fiscal year 2014 on the basis that management has determined that it is not probable that such events will ultimately result in a change 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 from 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 BPA administrator in July 2011. In 2011, BPA and many COUs filed respective motions in the Ninth Circuit Court to dismiss pending litigation challenging BPA’s former decisions related to the REP. Those decisions were stayed pending a decision from the Ninth Circuit on the merits of the 2012 REP Settlement Agreement. On October 28, 2013, the Court affirmed the 2012 REP Settlement Agreement. In May 2014, BPA, the IOUs, and many COUs filed renewed motions to dismiss on the grounds that such challenges were moot due to the 2012 REP Settlement Agreement and the Court’s October 28, 2013 ruling. The Court has not ruled on these motions to date.

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 REP 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. Management is unable to predict whether the FCRPS will avoid adverse outcomes in these legal matters; however, management 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 2014.

Judgments and settlements are included in FCRPS costs and recovered through rates. Except with respect to the SCE, California parties’ refund claims, and REP matters described above, no liability has been recorded for the above legal matters. (See Note 11, Deferred Credits and Other, for discussion of amounts accrued for outstanding legal claims and settlements.)

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APPENDIX C

FORM OF OPINION OF ORRICK, HERRINGTON & SUTCLIFFE LLP

(Date of Closing)

Port of Morrow
2 Marine Drive
P.O. Box 200
Boardman, OR 97818

Re: Port of Morrow
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 2)
Series 2014

Ladies and Gentlemen:

We have acted as special counsel to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") in connection with the issuance by the Port of Morrow (the "Issuer") of $193,075,000 aggregate principal amount of the Issuer's Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 2), Series 2014 (the "Series 2014 Bonds"), issued pursuant to an Indenture of Trust, dated as of December 1, 2014 (the "Indenture"), between the Issuer and U.S. Bank National Association, as trustee (the "Trustee"). The Series 2014 Bonds are issued for the purpose of refinancing indebtedness issued to finance a portion of the cost of acquiring, constructing, improving and equipping certain transmission facilities to be owned by the Issuer and leased to Bonneville pursuant to the Lease-Purchase Agreement, dated December 18, 2014 (the "Lease-Purchase Agreement"), between the Issuer and Bonneville. Capitalized terms not otherwise defined herein shall have the meanings ascribed to such terms in the Indenture.

In such connection, we have reviewed the Indenture, the Lease-Purchase Agreement, opinions of counsel to Bonneville, the Trustee and the Issuer, certain resolutions of the Issuer, certificates of the Issuer, the Trustee, Bonneville and others and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein, including the judicial validation the Issuer received pursuant to an Order, dated April 15, 2012, which, among other things, confirms the valid, legal and binding effect of the proceedings of the Issuer providing for and authorizing the issuance, sale, execution and delivery of the Series 2014 Bonds and the funding of the Project. With respect to the due organization and existence of the Issuer and the adoption of the authorizing resolution of the Issuer related to the Series 2014 Bonds, we have relied upon the opinion of Monahan, Grove & Tucker.

The opinions expressed herein are based on 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 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 Bonds has concluded with their issuance, and we disclaim any obligation to update this letter.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Issuer.

We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in such documents, and of the legal conclusions contained in the opinions referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Lease-Purchase Agreement.

We call attention to the fact that the rights and obligations under the Series 2014 Bonds, the Indenture and the Lease-Purchase Agreement and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other similar laws relating to or affecting creditors' rights, to the application of equitable principles and to the exercise of judicial discretion in appropriate cases. In addition, under Washington law, any provision of the Lease-Purchase Agreement requiring one party to pay the other party's attorneys' fees and costs in actions to enforce the provisions thereof will be construed to entitle the prevailing party in any action to be awarded reasonable attorneys' fees, costs and necessary disbursements. Also, notwithstanding any provisions in the Lease-Purchase Agreement to the effect that the Lease-Purchase Agreement reflects the entire understanding of the parties thereto with respect to the matters described therein, the courts of the State of Washington may consider extrinsic evidence of the circumstances surrounding the negotiation and execution of the Lease-Purchase Agreement to ascertain the intent of the parties in using the language employed in the Lease-Purchase Agreement, regardless of whether or not the meaning of the language used in the Lease-Purchase Agreement is plain and unambiguous on its face, and may determine that additional or supplemental terms can be incorporated into the Lease-Purchase Agreement. Furthermore, under Washington law, the parties to the Lease-Purchase Agreement can modify the Lease-Purchase Agreement by their conduct, and a party seeking to enforce the Lease-Purchase Agreement may be required to perform its obligations under the Lease-Purchase Agreement.

We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the foregoing documents nor do we express any opinion with regard to the state or quality of title to or interest in any of the real or personal property described in the Indenture or the Lease-Purchase Agreement or the accuracy or sufficiency of the description of any such property contained therein. Finally, we have undertaken no responsibility for the accuracy, completeness or fairness of the Official Statement or other offering material relating to the Series 2014 Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Series 2014 Bonds constitute the valid and binding limited recourse obligations of the Issuer, payable solely from the Trust Estate.

2. The Indenture constitutes the valid and binding obligation of the Issuer. The Indenture creates the valid pledge of the Trust Estate, subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture.

3. The Lease-Purchase Agreement constitutes the valid and binding agreement of the Issuer.

4. Interest on the Series 2014 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the U.S. Internal Revenue Code of 1986, as amended. Interest on the Series 2014 Bonds is exempt from present State of Oregon personal income taxation.

Very truly yours,

ORRICK, HERRINGTON, SUTCLIFFE LLP

Under 31 C.F.R. part 10, the regulations governing practice before the United States Internal Revenue Service (Circular 230), we are (or may be) required to inform you that the opinion set forth herein is not intended or written to be used, and cannot be used, by any taxpayer for the purpose of avoiding penalties that may be imposed on the taxpayer.

APPENDIX D

FORM OF CONTINUING DISCLOSURE CERTIFICATE

CONTINUING DISCLOSURE CERTIFICATE

$193,075,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 2)
Series 2014

This Continuing Disclosure Certificate (the "Certificate") is executed and delivered by the Bonneville Power Administration ("Bonneville") as the obligated person for whom financial and operating data is presented in the official statement for the Port of Morrow, Oregon (the "Issuer") Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 2) Series 2014 (the "Bonds").

Section 1. Purpose of Certificate. This Certificate is being executed and delivered by Bonneville for the benefit of the holders of the Bonds and to assist the underwriters of the Bonds in complying with paragraph (b)(5) of the United States Securities and Exchange Commission Rule 15c2-12 (17 C.F.R. § 240.15c2-12) as amended (the "Rule"). This Certificate constitutes Bonneville's written undertaking for the benefit of the owners of the Bonds as required by paragraph (b)(5) of the Rule.

Section 2. Definitions. Unless the context otherwise requires, the terms defined in this Section shall, for purposes of this Certificate, have the meanings herein specified.

"Beneficial Owner" means any person who has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of any Bonds, including persons holding Bonds through nominees or depositories.

"BPA Annual Information" means financial information and operating data generally of the type included in Appendix A of the Official Statement under the heading "POWER SERVICES" in the tables titled "Bonneville Power Services' Ten Largest Customers by Sales" and "Historical Average PF Preference Rates," under the heading "TRANSMISSION SERVICES" in the table titled "Transmission Services' Ten Largest Customers By Sales," and under the heading "BONNEVILLE FINANCIAL OPERATIONS" in the tables titled "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."

"Commission" means the United States Securities and Exchange Commission.

"FCRPS" means the Federal Columbia River Power System.

"FCRPS Fiscal Year" means the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year end is changed, Bonneville shall provide written notice of such change to the MSRB.

"MSRB" means the United States Municipal Securities Rulemaking Board or any successor to its functions.

"Official Statement" means the final official statement for the Bonds dated December 11, 2014.

"Rule" means the Commission's Rule 15c2-12 under the Securities Exchange Act of 1934, as it has been and may be amended.

Section 3. Financial Information. Bonneville agrees to provide or cause to be provided 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, 2015:

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 will notify the Issuer when the financial information in this section has been provided to the MSRB.

Bonneville agrees to notify the MSRB in a timely manner of any failure to provide the information described in Section 3 on or prior to the date set forth in the preceding paragraph.

Section 4. Events Notices. Bonneville agrees to provide to the MSRB and the Issuer in a timely manner not in excess of ten business days after the occurrence of the event, notice of any of the following events with respect to the Bonds:

1. principal and interest payment delinquencies;

2. non-payment related defaults, if material;

3. unscheduled draws on debt service reserves reflecting financial difficulties;

4. unscheduled draws on credit enhancements reflecting financial difficulties;

5. substitution of credit or liquidity providers or their failure to perform;

6. adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds;

7. modifications to the rights of Bondholders, if material;

8. bond calls, if material, and tender offers;

9. defeasances;

10. release, substitution or sale of property securing repayment of the Bonds, if material;

11. rating changes;

12. bankruptcy, insolvency, receivership or similar event of the obligated person (Note: For the purposes of the event identified in this paragraph 12, the event is considered to occur when any of the following occur: The appointment of a receiver, fiscal agent or similar officer for an obligated person 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 the obligated person, 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);

13. the consummation of a merger, consolidation, or acquisition involving an obligated person or the sale of all or substantially all of the assets of the obligated person, 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;

14. appointment of a successor or additional trustee or the change of name of a trustee, if material.

Section 5. Termination. Bonneville's obligations to provide notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Bonds. In addition, Bonneville may terminate all or any portion of its obligations under this Certificate if Bonneville (a) obtains an opinion of nationally recognized bond counsel to the effect that those portions of the Rule which require this Certificate, or any provision of this Certificate, are invalid, have been repealed retroactively or otherwise do not apply to the Bonds; and (b) notifies the MSRB of such opinion and the termination of its obligations under this Certificate.

Section 6. Amendment. Notwithstanding any other provision of this Certificate, Bonneville may amend this Certificate, provided that the following conditions are satisfied:

A. If the amendment relates to the provisions of Sections 3 or 5 hereof, it may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature or status of Bonneville with respect to the Bonds, or the type of business conducted; and,

B. If this Certificate, as amended, would, in the opinion of nationally recognized bond counsel, have complied with the requirements of the Rule at the time of the original issuance of the Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

C. The amendment either (i) is approved by the owners of the Bonds pursuant to the terms of the governing instrument at the time of the amendment or (ii) does not materially impair the interests of the owners or Beneficial Owners of the Bonds as determined by a party unaffiliated with the obligated person.

In the event of any amendment of a provision of this Certificate, Bonneville shall describe such amendment in its next annual filing pursuant to Section 3 of this Certificate, and shall include, as applicable, a narrative explanation of the reason for the amendment 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. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of the amendment shall be given in the same manner as for a listed event under Section 5 hereof, and (ii) the annual report for the first fiscal year that is affected by the change in accounting principles 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.

Section 7. Bond Owner's Remedies Under This Certificate. The right of any owner of Bonds or Beneficial Owner of Bonds to obtain legal redress for Bonneville's failure to comply with provisions of this Certificate, or for any breach or default by Bonneville of this Certificate, shall not include monetary damages and any failure by Bonneville to comply with the provisions of this Certificate shall not be an event of default with respect to the Bonds. Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Certificate. Any owner of Bonds or Beneficial Owner of Bonds shall have only such other rights and remedies available to it under federal law with respect to Bonneville.

Section 8. Form of Information. All information required to be provided under this certificate will be provided in an electronic format as prescribed by the MSRB and with the identifying information prescribed by the MSRB.

Section 9. Submitting Information Through EMMA. So long as the MSRB continues to approve the use of the Electronic Municipal Market Access ("EMMA") continuing disclosure service, any information required to be provided to the MSRB under this Certificate may be provided through EMMA. As of the date of this Certificate, the web portal for EMMA is emma.msrb.org.

Section 10. Choice of Law. This Certificate shall be governed by and construed in accordance with federal law, including federal securities laws and official interpretations thereof.

Dated as of the 18th day of December, 2014.

Bonneville Power Administration

____
Authorized Official