NEW ISSUE **BOOK-ENTRY-ONLY**

In the opinion of Special Counsel, interest on the Series 2012 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 2012 Bonds is exempt from present State of Oregon personal income taxation. See "TAX MATTERS – Certain State of Oregon Income Tax Considerations" herein.

$84,740,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1)
Series 2012 (Federally Taxable)
CUSIP No.: 73474TAA8*

Dated: Date of Delivery — Due: September 1, 2042

The Series 2012 Bonds will be special obligations of the Issuer payable solely from the trust estate pledged therefor which trust estate includes amounts derived from lease rental payments paid to the Issuer pursuant to a Lease 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 Agreement will be made solely from the Bonneville Fund. The Lease Agreement provides that Bonneville's obligation to pay the lease rental payments and all amounts payable under the Lease 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 2012 Bonds is operating or operable. Bonneville's payment obligations under the Lease 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 2012 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 2012 Bonds will bear interest at 3.675% per annum, payable on September 1, 2012 and semi-annually thereafter on March 1 and September 1 of each year.

The Series 2012 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 2012 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 2012 Bonds will not receive certificates representing their interest in the Series 2012 Bonds. Ownership interests in the Series 2012 Bonds will be shown on, and transfers of Series 2012 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 2012 Bonds will be made to owners by DTC through its participants.

The Trustee for the Series 2012 Bonds is U.S. Bank National Association.

The Series 2012 Bonds are subject to redemption prior to maturity as described herein.

Offering Price:
100%

The Series 2012 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of the proceedings authorizing the Series 2012 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 L.L.P., New York, New York. The Series 2012 Bonds are expected to be delivered through the facilities of DTC on or about July 24, 2012.

BofA Merrill Lynch

J.P. Morgan **Wells Fargo Securities**

July 18, 2012

* 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 Energy 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 Merrill Lynch, Pierce, Fenner & Smith Incorporated 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" 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 2012 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.

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

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OFFICIAL STATEMENT

$84,740,000
Port of Morrow, Oregon
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1),
Series 2012 (Federally Taxable)

INTRODUCTORY STATEMENT

This Official Statement provides information concerning the issuance by the Port of Morrow, Oregon (the "Issuer") of $84,740,000 principal amount of its Transmission Facilities Revenue Bonds, Series 2012 (the "Series 2012 Bonds"). The Series 2012 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 Agreement with Bonneville dated as of July 1, 2012 (the "Lease Agreement") pursuant to which the Issuer will lease the Project to Bonneville. The Series 2012 Bonds will be issued under an Indenture of Trust dated as of July 1, 2012 (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 Agreement, including the right to receive lease rental payments from Bonneville in amounts at least sufficient to pay when due the principal of, and interest, on the Series 2012 Bonds.

Brief descriptions and summaries of the Series 2012 Bonds, the Lease 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 Corporate Trust Services, 555 SW Oak Street, PD-OR-PTD, 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 11,000 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	07/01/09	06/30/13
Joe Taylor	Vice-President/Treasurer	Farmer	07/01/09	06/30/13
Larry Lindsay	Secretary	Farmer	07/01/11	06/30/15
Jerry Healy	Commissioner	General Manager, Columbia Basin Electric Co-op, Inc.	07/01/09	06/30/13
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 36 full-time equivalent employees to assist in administrative and facility maintenance activities.

Limited Obligation

The Series 2012 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 2012 Bonds, in the Lease 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 2012 Bondholders for the payment of the principal of, premium, if any, and interest on the Series 2012 Bonds in accordance with their terms and provisions of the Indenture. THE SERIES 2012 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 2012 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 2012 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 2012 BONDS OR THE INTEREST THEREON. THE LEASE 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 2012 Bonds, and any leases or indentures executed in connection with such transmission facilities, including the Indenture and Lease 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 June 12, 2007 and amended and restated as of December 9, 2010, between Bonneville and the Northwest Infrastructure Financing Corporation II ("NIFC II"), NIFC II provided for the acquisition, construction, installation and equipping of certain transmission assets (as described below, the "Project") and leased the Project to Bonneville. NIFC II 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 II, as lessor, and Bonneville, as lessee, and the payments from Bonneville thereunder.

The proceeds from the sale of the Series 2012 Bonds will be used by the Issuer to acquire the Project from NIFC II. NIFC II will use the funds received from the Issuer to pay the indebtedness incurred under the credit agreement to pay the cost of acquiring the Project. Upon receipt of the acquisition payment, NIFC II 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 2012 Bonds will also be used by the Issuer to pay the costs of issuance of the Series 2012 Bonds (including Underwriters' discount) and certain administrative costs of the Issuer. The costs of issuance and such administrative costs are expected to aggregate approximately $1,196,553.00.

THE PROJECT

As described herein under "THE LEASE 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 equipment that are a part of electric transmission system facilities located in the Pacific Northwest region of the United States. The Project includes four rebuilt transmission lines with conductor, insulators, ground wire, steel towers, steel poles, surge arresters, or wood poles. The Project also includes one control center upgrade with control center main grid map boards and wall displays; one radio station engine generator and radio system; and additions or replacements at eleven Bonneville substations for aluminum bus, circuit switchers, communication towers, control cable, converter capacitors, converter transformers, current transformers, disconnect switches, power circuit breakers, relay house, relay packages, revenue metering, or voltage transformers. 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 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. See "THE LEASE AGREEMENT - Changing the Definition of the Project."

The Series 2012 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 Agreement as described under "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2012 BONDS – Trust Estate." Therefore, the Bondholders should not look to the Project as providing any security for the payment of Bonds. See "THE PROJECT."

SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2012 BONDS

Trust Estate

Under the terms of the Indenture, the Series 2012 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 Agreement, including all lease 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 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 any special fund, and all investment earnings of any of the foregoing, subject to disbursements from the Project Fund, the Bond Fund or any such special fund in accordance with the provisions of the Lease 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 Agreement between Bonneville and the Issuer, Bonneville is required to make lease rental payments in the amounts set forth in a schedule set forth in the Lease Agreement which schedule will provide for lease 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 2012 Bonds. See herein "THE LEASE AGREEMENT" and "THE INDENTURE." Such lease 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 2012 Bonds. The Lease Agreement provides that such lease rental payments will be made directly to the Trustee for deposit in the Bond Fund.

The Lease Agreement provides that Bonneville's obligation to pay the lease rental payments and all other amounts payable under the Lease 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 lease rental payments will continue until September 1, 2042, unless sooner terminated or extended in accordance with the provisions of the Lease Agreement, and is coterminous with the maturity of the Series 2012 Bonds. **Bonneville's obligations under the Lease 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 lease term, 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 term and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease Agreement. The Issuer and Bonneville will declare that the Lease 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 2012 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 Agreement as described above. Therefore, the Bondholders should not look to the Project as providing any security for the payment of 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 Agreement are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations or the Series 2012 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 Bureau of 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 fiscal year 2011 payment responsibility to the United States Treasury in full and on time for the 28th 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 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 Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) to (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, 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. In addition, Bonneville is considering whether to establish a power prepayment program, which would have similar effects on Bonneville's revenues in cash as occurs under net billing. Under a power prepayment, in return for up-front lump sum prepayments of power by Bonneville's customers, Bonneville would provide fixed credits to their power purchases through September 30, 2028.

For additional descriptions of Bonneville's substantial net billing arrangements, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—POWER SERVICES—Description of the Generation Resources of the Federal System," "—BONNEVILLE FINANCIAL OPERATIONS—Energy Northwest Net Billing Agreements," "—BONNEVILLE FINANCIAL OPERATIONS—Direct Pay Agreements," and BONNEVILLE FINANCIAL OPERATIONS—Prepaid Power."

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 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 2012 BONDS

General

The Series 2012 Bonds will be issued originally as a single global certificate registered to DTC, or its nominee, Cede & Co., to be held in DTC's book-entry-only system. So long as the Series 2012 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 2012 Bonds for all purposes of the Indenture, the Series 2012 Bonds and this Official Statement. Interest on the Series 2012 Bonds will be payable only through participants or indirect participants in DTC so long as the Series 2012 Bonds are held in the book-entry-only system. See "Book-Entry-Only System" below.

The Series 2012 Bonds will be issued in the aggregate principal amount and will bear interest, computed on the basis of a 360-day year of twelve 30-day months, at the annual rate set forth on the cover page hereof. The Series 2012 Bonds will mature as set forth on the cover page of this Official Statement. The Series 2012 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 2012 Bonds, are referred to as the "Bonds."

Interest on the Series 2012 Bonds will be payable on March 1 and September 1 of each year, commencing September 1, 2012, to the persons in whose name the Series 2012 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 2012 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 2012 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 2012 Bonds.

Book-Entry-Only System

DTC will act as securities depository for the Series 2012 Bonds. The Series 2012 Bonds will be issued as fully-registered Series 2012 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 2012 Bond will be issued for the Series 2012 Bonds, in the aggregate principal amount of such issue, 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 2012 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2012 Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2012 Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Series 2012 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Series 2012 Bonds, except in the event that use of the book-entry-only system for the Series 2012 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2012 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 2012 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2012 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2012 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 2012 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the Series 2012 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2012 Bond documents. For example, Beneficial Owners of Series 2012 Bonds may wish to ascertain that the nominee holding the Series 2012 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 2012 BONDS.

Redemption notices will be sent to DTC. If less than all of the Series 2012 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Series 2012 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 2012 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Series 2012 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 2012 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 2012 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 2012 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 2012 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 2012 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 2012 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 2012 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS OR OWNERS OR REGISTERED HOLDERS OR REGISTERED OWNERS OF THE SERIES 2012 BONDS MEANS CEDE & CO., AS AFORESAID, AND DOES NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2012 BONDS.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2012 Bonds, payment of principal, interest and other payments on the Series 2012 Bonds to Direct and Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Series 2012 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 2012 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 2012 Bonds as shown on the cover page of this Official Statement (but not less than 100% of the principal amount of the Series 2012 Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2012 Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2012 Bonds are to be redeemed, discounted to the date on which such Series 2012 Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below) plus 20 basis points, plus accrued and unpaid interest on the Series 2012 Bonds to be redeemed on the redemption date.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2012 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 2012 Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2012 Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such Series 2012 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 2012 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 2012 Bonds are to be redeemed, the Issuer may select the maturity or maturities to be redeemed. If less than all of the Series 2012 Bonds of any maturity are to be redeemed, the Series 2012 Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, in accordance with their respective standard procedures. The Indenture provides that the portion of any Series 2012 Bonds of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such Series 2012 Bonds for redemption, the Trustee will treat each such Series 2012 Bonds as representing that number of such Series 2012 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2012 Bonds to be redeemed in part by $5,000.

The particular Series 2012 Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2012 Bonds are registered in book-entry-only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2012 Bonds, if less than all of a maturity of the Series 2012 Bonds of a maturity are called for redemption, the particular Series 2012 Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2012 Bonds are held in book-entry-only form, the selection for redemption of such Series 2012 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 2012 Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2012 Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

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

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

Notice of Redemption

Notice of redemption of any Series 2012 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 2012 Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2012 Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2012 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 2012 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2012 Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if money sufficient for the redemption of the Series 2012 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2012 Bonds on the redemption date and the Series 2012 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 2012 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2012 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 2012 BONDS – Book-Entry-Only System") will determine the particular ownership interests of Series 2012 Bonds to be redeemed. Any failure of DTC or its successor or a Participant or Indirect Participant to do so, or to notify a Beneficial Owner of a Series 2012 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2012 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 2012 Bonds, or that they will do so on a timely basis.

THE LEASE AGREEMENT

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

Lease Rental Payments

Bonneville agrees under the Lease Agreement to pay to the Trustee lease rental payments for deposit in the Bond Fund created under the Indenture in the amounts set forth in a schedule to the Lease Agreement, which schedule provides for lease rental payments more than sufficient for the payment of the principal of, and interest on, the Series 2012 Bonds. The obligation of Bonneville to make all payments provided in the Lease Agreement is stated to be absolute and unconditional. See "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2012 BONDS" herein.

Bonneville has also agreed to pay as additional rent under the Lease 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 Agreement, any estate or interest of the Issuer or Bonneville in the Project or transfer of such estate or interest, or the lease rental payments under the Lease Agreement during the term of the Lease 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 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); 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 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 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 Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the lease rental payments or other amounts payable by Bonneville under the Lease 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 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 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 2012 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 Agreement.

Damage, Destruction and Condemnation

If the Project is damaged, destroyed or condemned, there will be no reduction in the lease rental payments or other amounts payable under the Lease 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 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 lease 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 Agreement

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

Defaults

The Lease 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 lease rental payment that has become due and payable under the Lease Agreement;

(b) Failure of Bonneville to pay any amount due under the Lease Agreement (other than under paragraph (a) above) and continuance of such default 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 Agreement, other than as referred to 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.

Remedies

Upon the occurrence and continuance of an Event of Default under the Lease 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 lease rental payment then due and thereafter to become due, or to enforce performance and observance of any obligations, agreements or covenants of Bonneville under the Lease 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 lease term, 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 Term and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease Agreement. The Issuer and Bonneville declare that the Lease 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 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 Agreement and not by the market value of the Project or a leasehold interest in the Project.

Options

Under the Lease Agreement, Bonneville has the option, at any time and from time to time, to make advance lease 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 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 series of the Bonds allocable to such component or portion. Bonneville or its assignee will exercise its option to make such advance lease 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 lease rental payment or purchase option payment, (ii) the principal amount of Bonds Outstanding requested to be redeemed with such advance lease 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 lease 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 lease rental payment payable pursuant to the Lease 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 an appendix to the Lease Agreement) or by such other amount agreed to by the Issuer and Bonneville with the consent of the Trustee; provided that 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 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 lease 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 Agreement, except the obligation of Bonneville to make payments required to be made under the Lease 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 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 lease rental payments and other payments under the Lease 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 at least 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 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 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 Agreement." A change in the definition of the Project pursuant to the Lease Agreement will not constitute an amendment to the Lease Agreement. See "THE LEASE AGREEMENT – Changing the Definition of the Project."

Changing the Definition of the Project

Under the Lease 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 lease 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 Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the lease rental payments or other amounts payable by Bonneville under the Lease 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 Agreement. In the event of a re-definition of the Project, there is no obligation or special right to call any of the Series 2012 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 2012 Bonds, and to the extent the amounts are so applied, they will constitute a contribution to lease 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 2012 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 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 Agreement. See "THE LEASE AGREEMENT - Amendment," and "THE INDENTURE - Amendment of the Lease 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 Agreement, including all amounts (excluding payments for indemnification and certain other payments thereunder) to be received by the Issuer pursuant to the Lease 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 2012 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 II, and to pay expenses incurred in connection with the issuance and sale of the Series 2012 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 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, improvements or facilities 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 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 2012 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 Agreement.

Pursuant to the Lease 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 anytime, 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 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 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 Agreement (a) for the purpose of curing any ambiguity, formal defect or omission therein, (b) which, by the terms of the Lease 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 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 lease rental payments under the Lease Agreement with respect to the Bonds. Separate and apart from the amendment of the Lease Agreement, the Issuer and Bonneville will reserve the right to amend the definition of the Project. See THE LEASE 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 under the Indenture shall cease, terminate and be void and the Trustee shall cancel and discharge the lien and security interests 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, Bonneville has not included in its reports an update of the table of Operating Federal System Projects for Operating Year 2012 (contained in Appendix A under "POWER SERVICES – Operating Federal Systems Projects for Operating Year 2012"), 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 Bonneville intends to file amended or supplemental reports including updates of such table in the near future.

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 2012 Bonds.

RATINGS

Moody's Investors Service ("Moody's") and Fitch Ratings ("Fitch") have assigned the Series 2012 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 2012 Bonds. Such ratings reflect only the respective views of such rating agencies, and an explanation of the significance of such ratings may be obtained only from the rating agency furnishing the same. There is no assurance that any or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Series 2012 Bonds.

UNDERWRITING

Merrill Lynch, Pierce, Fenner & Smith Incorporated and the other Underwriters (the "Underwriters") of the Series 2012 Bonds have jointly and severally agreed, subject to certain conditions, to purchase the Series 2012 Bonds from the Issuer at an underwriters' discount of $483,909.20 and to reoffer the Series 2012 Bonds at the initial public offering price set forth on the cover page hereof. The Underwriters have agreed to purchase all of the Series 2012 Bonds if any are purchased. The Series 2012 Bonds may be offered and sold to certain dealers (including dealers depositing Series 2012 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 2012 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.

J.P. Morgan Securities LLC ("JPMS") has entered into negotiated dealer agreements (each, a "Dealer Agreement") with each of UBS Financial Services Inc. ("UBSFS") and Charles Schwab & Co., Inc. ("CS&Co.") for the retail distribution of certain securities offerings, including the 2012 Series A Bonds, at the original issue prices. Pursuant to each Dealer Agreement, each of UBSFS and CS&Co. will purchase the 2012 Series Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any 2012 Series Bonds that such firm sells.

Wells Fargo Securities is the trade name for the capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including Wells Fargo Bank, National Association ("WFBNA"). WFBNA has entered into an agreement (the "Distribution Agreement") with Wells Fargo Advisors, LLC ("WFA") for the retail distribution of certain municipal securities offerings, including the 2012 Series A Bonds. Pursuant to the Distribution Agreement, WFBNA will share a portion of its underwriting compensation with respect to the 2012 Series Bonds with WFA. WFBNA and WFA are both 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

Merrill Lynch, Pierce, Fenner & Smith Incorporated, an Underwriter of the 2012 Series Bonds, is an affiliate of Bank of America, N.A., which provided the loan to NIFC II to construct and acquire the Project and has extended credit to Bonneville in unrelated transactions.

J.P. Morgan Securities LLC, an Underwriter of the 2012 Series Bonds, is an affiliate of JPMorgan Chase Bank, N.A., which has extended credit to Bonneville in unrelated transactions.

Wells Fargo Bank, National Association, is serving as both an Underwriter of the 2012 Series Bonds and has extended credit to Bonneville in unrelated transactions.

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 2012 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 2012 Bonds.

If the Issuer defeases any Series 2012 Bond, such Series 2012 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 2012 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 2012 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 2012 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 2012 Bonds is exempt from present State of Oregon personal income taxation.

LEGAL MATTERS

Legal matters incident to the authorization and issuance of the Series 2012 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 L.L.P., New York, New York.

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") by Bonneville for use in the Official Statement, dated July 18, 2012, furnished by the Issuer (the "Official Statement") with respect to its Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1), Series 2012 (the "2012 Bonds"). The Project is described in the Official Statement under "THE PROJECT." Such information is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, is true and correct and does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this Appendix A and in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

GENERAL

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

Bonneville's primary enabling legislation includes the following Federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 Federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-Federally-owned and -operated projects, including 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 of about 10,813 annual average megawatts (defined below) under median water conditions and about 8,757 annual average megawatts under low water conditions. (Bonneville's "Operating Year" runs from August 1 through July 31. By contrast, its "Fiscal Year" runs from October 1 through September 30.) (Annual average megawatts are the number of megawatt-hours of electric energy used, transmitted, or produced over the course of one year and each annual average megawatt is equal to 8,760 megawatt-hours.)

Bonneville sells, purchases, and exchanges firm power, seasonal surplus energy (which is also referred to as "secondary" or "non-firm" energy), peaking capacity, and related power services. Bonneville also constructed, owns, operates, and maintains a high voltage transmission system (the "Federal Transmission System") comprising approximately three-fourths of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities, owners of generation projects, and power marketers. Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada, northern Utah, and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the 300,000 square-mile service area is approximately 12 million people. Electric power sold by Bonneville accounts for more than one-third of the electric power consumed within the Region.

Bonneville markets a large portion of this power to over 125 publicly-owned and cooperatively-owned utilities ("Preference Customers") at wholesale, meaning for resale by the utilities to end-use consumers in the Region. Bonneville also has contracts to sell power for direct consumption to several Federal agencies and a small number of companies ("Direct Service Industries" or "DSIs") located in the Region. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," has resulted and is expected to continue to result in substantial payments by Bonneville to the exchanging utilities. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"), of which there are six. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

The Transmission System Act placed Bonneville on a self-financing basis, meaning that Bonneville pays its costs from revenues it receives from the sale of power and the provision of transmission and other services, which Bonneville provides at rates that seek to produce revenues that recover Bonneville's costs, including certain payments to the United States Treasury. Bonneville's rates for the foregoing services are subject to approval by the Federal Energy Regulatory Commission ("FERC") on the basis that, among other things, they recover Bonneville's costs. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates." Bonneville may also issue and sell bonds to the United States Treasury and use the proceeds thereof to fund certain activities established under Federal law.

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

Bonneville's cash receipts from all sources, including from both transmission and power services, must be deposited in the Bonneville Power Administration Fund (the "Bonneville Fund"), which is a separate fund within the United States Treasury and which is available to pay Bonneville's costs. In accordance with the Transmission System Act, Bonneville must make expenditures from the Bonneville Fund as "shall have been included in annual budgets submitted to Congress, without further appropriation and without fiscal year limitation, but within such specific directives or limitations as may be included in appropriation acts, for any purpose necessary or appropriate to carry out the duties imposed upon [Bonneville] pursuant to law."

Bonneville is required to make certain payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal Columbia River Power System ("Federal System") other than payments to the United States Treasury for: (i) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at Federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the Corps and Reclamation for certain costs allocated to power generation at Federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its payment responsibility to the United States Treasury of $830 million (including $70 million in principal payments in advance of due dates) in full and on time for Bonneville's fiscal year ended September 30, 2011 ("Fiscal Year 2011"). Bonneville has made all payments to the United States Treasury in full and on time since 1984. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including lease rental payments under the Lease Agreement and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. For a description of the Lease Agreement, see the Official Statement under the heading "THE LEASE 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 lease rental payments under the Lease 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 2012 BONDS."

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. In the event of such a deferral, Bonneville is required to take action, for example by increasing rates or reducing costs, to assure that it has sufficient funds to repay the deferred amounts, with interest in future years.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Regional Power Sales

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

Power Sales to Preference Customers

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

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

In contrast to the Prior Preference Contracts, the Long-Term Preference Contracts restrict the power that Preference Customers may purchase in aggregate at "Tier 1 PF Rates," in general, to an amount equal to the generating output of the currently existing Federal System. Tier 1 PF Rates will reflect, in general, the low, embedded costs of the existing Federal System. Power for "Tier 2 Loads," meaning any net requirements load placed on Bonneville by a customer in excess of its right to purchase at Tier 1 PF Rates, will be sold at "Tier 2 PF Rates" that recover the cost to Bonneville of acquiring the incremental electric power needed to meet Tier 2 Loads. For all Preference Customers purchasing power from Bonneville to meet Tier 2 Loads, such purchases will be integrated with purchases of power for Tier 1 Loads into a single power purchase. The purchase of power from Bonneville for Tier 2 Loads will be made on a take-or-pay basis for the specified amount of power.

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

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

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

For a more detailed description of the Long-Term Preference Contracts, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region— Long-Term Preference Contracts."

Power Sales to DSIs

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

Bonneville's service to DSIs is and has been the subject of litigation. The United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which is a Federal appeals court with limited original jurisdiction over many matters relating to Bonneville, has issued two separate opinions that concluded that certain prior power sales by Bonneville to a DSI were not consistent with Bonneville's governing laws. See "BONNEVILLE LITIGATION—DSI Service Litigation."

Other Requirements Power Sales in the Region

While Bonneville is directed by law to do so under certain circumstances, Bonneville does not currently, nor does Bonneville expect to, sell Regional IOUs power to meet their net requirements loads until at least Fiscal Year 2020. See "POWER SERVICES—Customer and Other Power Contract Parties of Bonneville's Power Services—Regional Investor-Owned Utilities."

Bonneville also sells Full Requirements power to eight Federal agencies to meet their loads, which Bonneville estimates are about 117 annual average megawatts in Operating Year 2012.

Loads and Resources Expectations

Bonneville expects that, in aggregate, its total power sales obligations will be about 8,767 annual average megawatts in Operating Year 2012 and will be about 8,436 annual average megawatts in Operating Year 2013. Of these loads: (i) the aggregate of Preference Customer, Federal agency, and DSI loads are forecast to increase from 7,405 annual average megawatts in Operating Year 2012 to 7,453 annual average megawatts in Operating Year 2013, and (ii) other Bonneville exports and intra-regional contract obligations are forecast to decrease from about 1,362 annual average megawatts in Operating Year 2012 to 983 annual average megawatts in Operating Year 2013. By contrast, Bonneville estimates that the Federal System will be able to produce, under certain assumptions of historically low water conditions, about 8,757 annual average megawatts in Operating Year 2012 (See the table entitled "Operating Federal System Projects for Operating Year 2012"), decreasing to 8,586 annual average megawatts in Operating Year 2013. (The estimate also takes into account power purchases.) Bonneville has adequate resources to meet its power sales obligations in Operating Year 2012. See "POWER SERVICES—Description of the Generation Resources of the Federal System."

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

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

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

Consideration of a Prepaid Power Program

Bonneville is exploring with its customers whether to establish a prepaid power program in which one or more Preference Customers would provide lump sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028, the termination date of the Long-Term Preference Contracts. In return, those Preference Customers would become entitled to future deliveries of a portion of electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments would be represented by fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayment is not for a fixed block of electricity. The prepayment will entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then applicable power rates.

The program under consideration would involve determining the amount of the prepayments and the amount of resulting credits through a competitive process in which Preference Customers would bid to participate in the program in two-year cycles tied to Bonneville's two-year power rate periods. The program would be sequenced so that Bonneville would know the prepayment amounts and credits in setting power rates for the applicable rate period. Bonneville would expect to expend the amounts it receives through the prepayment program by the end of each such two-year rate period. If it were to proceed with the program, Bonneville is considering accepting up to roughly $500 million of prepayments in Fiscal Year 2013, resulting in approximately $4.35 million to $4.65 million of credits per month through Fiscal Year 2028. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

2012 Residential Exchange Program Settlement

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

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

Bonneville Rates for the 2012-2013 Rate Period

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

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

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

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

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

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

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

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

Fiscal Year 2011 Financial Results

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

Fiscal Year 2012 Expectations

Current analyses prepared outside of Bonneville (by the Northwest River Forecast Center) and relied on by Bonneville for planning purposes indicate a water supply forecast for the Columbia River basin, as of July 18, 2012, of 121 percent of the 30-year average for Fiscal Year 2012, as measured in terms of millions of acre feet of water or "MAF." Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and British Columbia.

Forecasts indicate continued low market prices for energy primarily due to the availability of energy from generators that use natural gas, the market price of which is at low levels. Bonneville expects that the lower-than-expected prices for secondary energy in Fiscal Year 2012 may adversely affect Bonneville's net revenues. Bonneville expects that Power Services will not meet the projection of $53 million in net revenues in Fiscal Year 2012 as forecasted in developing the 2012-2013 Rates. As of April 27, 2012, Bonneville estimated that financial reserves will be approximately $868 million at the end of Fiscal Year 2012 as compared to $1.01 billion as of the end of Fiscal Year 2011. Financial reserves are composed of Bonneville cash, special investments held in the Bonneville Fund, and deferred borrowing from the United States Treasury and are affected by numerous factors including estimates of revenues and expenses for the year, increases or decreases in cash and cash equivalents related to the timing of collections and payments, capital expenditures, and principal and interest payments to the United States Treasury.

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

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

Energy Northwest Depleted Uranium Enrichment Program

In May 2012, the Executive Board of Energy Northwest approved participation in a depleted uranium enrichment program (the "Uranium Program") to provide fuel for the Columbia Generating Station. Energy Northwest has entered a credit agreement pursuant to which it may borrow up to $200 million to pay the cost of acquiring such fuel and plans to issue approximately $700 million of bonds to refinance such borrowing and pay the remaining cost of acquiring such fuel. Debt service and capital expenditures for the Columbia Generating Station are funded by Bonneville pursuant to certain Net Billing Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Energy Northwest Net Billing Agreements." Bonneville issued a letter of non-disapproval of the Uranium Program to Energy Northwest. As required by the Columbia Generating Station Project Agreement, Energy Northwest submits proposals for budgets, plans, actions, activities, or matters to the Bonneville Power Administrator for approval. Bonneville's practice, when it does not disagree with the Energy Northwest proposals, is to provide Energy Northwest with a letter stating that it does not disapprove the proposals. Under the Columbia Generating Station Project Agreement, if any proposal is disapproved by Bonneville and Energy Northwest does not adopt Bonneville's suggestion, a project consultant is appointed to arbitrate whether the disapproved item was consistent with "Prudent Utility Practice" as defined in the Project Agreement.

Under the Uranium Program, DOE has agreed to provide approximately 9,082 metric tons of depleted uranium hexafluoride ("Uranium Tailings") at no cost to Energy Northwest. The Uranium Tailings will be physically transferred from DOE ownership to Energy Northwest ownership at the Paducah Gaseous Diffusion Plant ("PGDP") in Paducah, Kentucky where the Uranium Tailings will be enriched to a level necessary for fabrication into commercial nuclear fuel (the Uranium Tailings as so enriched, the "Enriched Uranium"). The PGDP is on land leased from DOE to the United States Enrichment Corporation ("USEC") and is operated by USEC.

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

The Energy Northwest and DOE agreement for the transfer of Uranium Tailings and the storage of the Enriched Uranium (the "Energy Northwest/DOE Agreement") terminates on December 31, 2022, when Energy Northwest's expected need for storage ends. Energy Northwest will pay the actual cost, in an amount not to exceed $5 million, to DOE for delivery and storage over the term of the Energy Northwest/DOE Agreement. DOE made the first delivery of Uranium Tailings in May 2012 and expects to make further deliveries through April 2013.

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

Coincident with the Energy Northwest/DOE Agreement, Energy Northwest and USEC entered into an agreement (the "Energy Northwest/USEC Agreement") that obligates USEC to enrich the Uranium Tailings delivered from DOE. Energy Northwest expects to receive approximately 482 metric tons of Enriched Uranium. The Energy Northwest/USEC Agreement commits USEC to enrich the delivered Uranium Tailings in 2012 and 2013 and terminates on December 31, 2013, or the date on which all enrichment and payment obligations are fulfilled. Energy Northwest's payments to USEC are tied to the amount of Uranium Tailings actually processed and are expected to be approximately $700 million. Deliveries and payments are expected to occur twice each month.

USEC has filed information with the Securities and Exchange Commission that raises various risk factors that could materially and adversely affect its business, results of operations and viability. To address these risks, Energy Northwest's obligation to deliver Uranium Tailings to USEC is conditioned on DOE's performance and delivery of Uranium Tailings under the Energy Northwest/DOE Agreement. Energy Northwest is obligated to pay USEC only after the Enriched Uranium is delivered to DOE for storage and its quality and quantity are validated by a third party. USEC is obligated to deliver to Energy Northwest title to the Enriched Uranium free of any liens by USEC's secured creditors. Energy Northwest may terminate the Energy Northwest/USEC Agreement if the Energy Northwest/DOE Agreement terminates for reasons other than Energy Northwest's breach or non-performance. Energy Northwest also may terminate the Energy Northwest/USEC Agreement if TVA ceases to supply electrical power to the PGDP. Energy supply is essential to the enrichment process and is a very large cost component of the enrichment process.

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

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

Pending Retirement of Bonneville Power Administrator, Stephen J. Wright

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

POWER SERVICES

Bonneville's Power Services is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. Power Services was responsible for about $2.5 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 77 percent, of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2011.

Description of the Generation Resources of the Federal System

Generation

Bonneville has statutory obligations to meet certain electric power loads placed on it by certain Regional customers. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." To meet these loads, Bonneville relies on an array of power resources and power purchases, which, together with the Bonneville-owned Federal Transmission System and certain other features, constitute the Federal System. The Federal System includes those portions of the Federal investment in the Regional hydroelectric projects that have been allocated by Federal law or policy to power generation. Such projects were constructed and are operated by the Corps or Reclamation. The Federal System also includes power from non-Federally-owned generating resources, including but not limited to the Columbia Generating Station, and contract purchases from and other arrangements with power suppliers.

Bonneville defines "firm power" as electric power that is continuously available from the Federal System during adverse water conditions to meet Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on assumptions related to a low-water period on record for the Columbia River basin referred to as "Critical Water." Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity (measured in megawatts) and firm energy (measured in average megawatts). Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2012 (August 1, 2011 through July 31, 2012), the total Federal System would be capable of producing about 8,757 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes about 6,846 annual average megawatts from Reclamation and Corps hydro projects, about 1,158 annual average megawatts from Columbia Generating Station and other non-Federally owned resources (including co-generation, renewable, and non-utility generation projects), and about 753 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 2012 below."

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 2012 is estimated to be approximately 79 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 2012."

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

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most months and in most water years. Bonneville estimates that in most months of an operating year and under most water and load conditions its peaking capacity, for long-term planning purposes, will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because as Bonneville acquires new resources or augments to balance annual and seasonal firm energy needs, these resource additions will also contribute more peaking capacity. At this time, Bonneville's resource planning focuses primarily on the need to develop sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal-, gas-, oil-, and nuclear-based generating systems must focus their resource planning on having enough peaking capacity to meet peak loads. As additional non-power requirements are placed on the Federal System hydroelectric operations and as peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity resources or purchases to meet peak loads.

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

In general, for long-term planning purposes Bonneville estimates the amount of electric power it will need to meet loads above the expected Federal System firm power generated under Critical Water. For ratemaking and financial planning purposes, however, Bonneville takes into account the amount of electric power it expects to have available to market based on water conditions that reflect average circumstances. The energy that Bonneville has to market above Critical Water assumptions in a specified period is referred to as seasonal surplus (secondary) energy. The amount of seasonal surplus (secondary) energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2012, the Federal System is estimated to generate seasonal surplus (secondary) energy of 1,203 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 2,602 annual average megawatts. In low water years, the amount of seasonal surplus (secondary) energy generated by the Federal System could be quite small or not available at all.

The Corps and Reclamation operate the Federally-owned hydroelectric projects of the Federal System to serve multiple statutory purposes. These purposes include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection, and power generation. Non-power purposes have placed requirements on operation of the reservoirs and have thereby limited hydropower production. Bonneville takes into account the non-power requirements and other factors in assessing the marketable power from these projects.

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

Other Power Resources and Contract Purchases

The balance of the Federal System includes, among other resources, power from the Columbia Generating Station, which has the largest capacity for energy production of the non-Federal resources of the Federal System. See Footnote 10 in the following table "Operating Federal System Projects for Operating Year 2012." In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. Bonneville projects that it will continue to have long-term contracts for power purchases, exchanges, and other non-Federal transactions that provide roughly 722 annual average megawatts.

Operating Federal System Projects for Operating Year 2012

In all years, the energy generating capability of the Federal System's hydroelectric projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, stream-flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a 70-year record of river flows based on the period from 1929-1998 for planning purposes. During this period, low water conditions ("Low Water Flows") occurred in 1936-37, median water conditions ("Median Water Flows") occurred in 1957-58, and high water conditions ("High Water Flows") occurred in 1973-74. Bonneville estimates the energy generating capability of Federal System hydroelectric projects in a given operating year by assuming that these historical water conditions occur in that operating year and making adjustments in the expected generating capability to reflect the current physical capacity operating limitations and current stream flow requirements. Energy generation estimates are further refined to reflect factors unique to the subject operating year such as initial storage reservoir conditions.

The following table shows, for Operating Year 2012, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows (referred to as "Firm Energy"), Median Water Flows (referred to as "Median Energy"), and High Water Flows (referred to as "Maximum Energy"). The same forecasting procedures are also used for non-Federally-owned hydroelectric projects. Thermal projects, the output of which does not vary with river flow conditions, are estimated using current generating capacity, plant capacity factors, and maintenance schedules.

Operating Federal System Projects for Operating Year 2012[(1)]

Project	Initial Year in Service	No. of Generating Units	January Capacity (Peak MW)(2)	Maximum Energy (aMW)(3)	Median Energy (aMW)(4)	Firm Energy (aMW)(5)
United States Bureau of Reclamation (Reclamation) Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	6,162	2,649	2,396	1,914
Hungry Horse	1952	4	366	150	103	82
Other Reclamation Projects(6)		16	125	182	170	126
1. Total Reclamation Projects		53	6,653	2,981	2,669	2,122
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph(7)	1955	27	2,535	1,356	1,295	1,102
John Day	1968	16	2,484	1,371	1,069	811
The Dalles w/o Fishway(8)	1957	24	2,034	979	811	607
Bonneville	1938	20	1,054	581	557	414
McNary	1953	14	1,127	718	643	494
Lower Granite	1975	6	930	405	289	191
Lower Monumental	1969	6	923	447	313	191
Little Goose	1970	6	928	422	299	193
Ice Harbor	1961	6	693	357	230	169
Libby	1975	5	579	273	214	177
Dworshak	1974	3	445	286	218	148
Other Corps Projects(9)		20	210	313	278	227
2. Total Corps Projects		153	13,942	7,508	6,216	4,724
3. Total Reclamation and Corps Projects (line 1 + line 2)		**206**	**20,595**	**10,489**	**8,885**	**6,846**
Non-Federally-Owned Projects						
Columbia Generating Station(10)	1984	1	1,130	1,030	1,030	1,030
Other Non-Federal Hydro Projects(11)		7	23	61	46	39
Other Non-Federal Projects(12)		11	28	89	89	89
4. Total Non-Federally-Owned Projects		**19**	**1,181**	**1,180**	**1,165**	**1,158**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(13)		**n/a**	**1,195**	**772**	**763**	**753**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**225**	**22,971**	**12,441**	**10,813**	**8,757**

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

(1) Operating Year 2012 is August 1, 2011, through July 31, 2012. Discrepancies from the figures portrayed in the "2011 Pacific Northwest Loads and Resources Study" are due to rounding.

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

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows for energy in average megawatts. The hydro-regulation study incorporates measures prescribed by the NOAA Fisheries biological opinions relating to the Columbia River and tributaries and court-ordered operations; the

Fish and Wildlife Service biological opinion for the Snake River and Columbia River dams; operations described in the Council's Fish and Wildlife Program; and other fish mitigation measures. If and to the extent the effects of new biological opinions or other measures to protect fish and wildlife are different than those assumed in the 2011 Pacific Northwest Loads and Resources Study, such changes will be reflected in future hydro-regulation studies. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

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

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

(6) Other Reclamation Projects include: Palisades (1957), Anderson Ranch (1950), Chandler (1956), Green Springs (1960), Minidoka (1909), Black Canyon (1925), Boise Diversion (1908), and Roza (1958).

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

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

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

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station will provide about 878 annual average megawatts in most refueling years and 1,030 annual average megawatts in non-refueling years. For Operating Year 2012, Columbia Generating Station is not scheduled for a refueling and is expected to provide about 1,030 annual average megawatts. This amount does not take into account any reductions in generation requested by Bonneville related to oversupply events. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System—Over-generation from High Water and High Wind."

(11) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Lewis County PUD's Cowlitz Falls Project (1994), the Glines Canyon Hydro Project (1927), which was retired February 13, 2012, and Elwha Hydro Project (1910), which was retired January 2, 2012, and the Idaho Falls Power Bulb Turbine Projects (1982). Bonneville has acquired the output from the Idaho Falls Power Bulb Turbine Projects (1982) through September 30, 2021. If Bonneville's contracts to purchase power from any of these projects are renewed, those projects will be included in future studies.

(12) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's Wauna Cogeneration Project (1996), the State of Idaho DWR's Clearwater Hydro (1998) and Dworshak Small Hydro (2000) 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), and a share of the City of Ashland's solar project.

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

Bonneville's Power Trading Floor Activities

Much of Bonneville's resource base is provided by hydroelectric facilities, the output of which is affected by weather conditions, stream-flows, operating constraints, and other factors. In most years, Bonneville sells substantial amounts of seasonal surplus (secondary) energy in market-based transactions. In addition, other generation conditions and requirements generally may affect generation output. Thus, actual generation availability and output may vary hourly, daily, monthly, or seasonally. In addition, power loads fluctuate based on consumer usage, demands to maintain transmission system stability, and other factors. Thus, loads and availability of generation from Bonneville's own resources can vary substantially and, on an operational basis during a year, actual power from Bonneville's own generating resources may not match its loads. In the near-term (prior to and during a fiscal year), Bonneville routinely produces probabilistic and discrete studies estimating potential surplus or deficits for specific future time periods. Based on these studies and specific marketing guidelines, Bonneville actively manages short-term surpluses and deficits through real-time, within-month, and forward sales and purchases, and physical power options.

Bonneville believes that its revenues and expenses from market transactions are, and will be, subject to several key risks: (i) the availability of electric power supplies generally and the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from discretionary sales of energy and the cost of necessary power purchases Bonneville may have to make to meet contracted loads; (ii) the level of Bonneville's load serving obligation; (iii) water conditions in the Columbia River basin, which determine the amount of hydroelectric power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (iv) changes in fish protection requirements, which could be the source of substantial additional expense to Bonneville and could further affect the amount and value of hydroelectric power from the Federal System; (v) continued availability of the capability of existing generating resources; and (vi) operating costs, generally.

Bonneville has put in place risk management procedures, standards, and policies that it believes adequately mitigate risk from these activities. Nonetheless, Bonneville's exposure to operational variability means that Bonneville may in certain conditions have to incur substantial purchased power expense. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—2010 Dodd-Frank Act and Bonneville."

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

Bonneville's primary transacting counterparties are composed of four principal groups: Preference Customers, DSIs, Regional IOUs, and Market Counterparties. Under the Northwest Power Act, Bonneville has a statutory obligation to meet electric power loads in the Region that are placed on Bonneville by electric power utilities. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region."

Preference Customers

Bonneville's primary customer base is composed of Preference Customers which make long-term power purchases from Bonneville at cost-based rates to meet their native loads in the Region. Preference Customers are qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, and they are entitled by law to a preference and priority ("Public Preference") in the purchase of available Federal System power for their load requirements in the Region. Such customers are eligible to purchase power at Bonneville's lowest cost rate, the PF Preference Rate, for most of their loads. Under Public Preference, Bonneville must meet a Preference Customer's request for available Federal System power in preference to a competing request from a non-Preference Customer. In the opinion of Bonneville's General Counsel, Public Preference does not compel Bonneville to lower the offered price of uncommitted surplus Bonneville power to Preference Customers before meeting a competing request at a higher price for such uncommitted power from a non-Preference Customer. Bonneville sells power to certain large Preference Customers under market-type contracts other than for their own load requirements. Bonneville also sells relatively small amounts of power to several Federal agencies in the Region. While such Federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at the PF Preference Rate.

Direct Service Industrial Customers

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

Regional Investor-Owned Utilities

As required by the Northwest Power Act, Bonneville has offered, and four of the six Regional IOUs have agreed to, contracts under which Bonneville could serve Regional IOUs with electric power for their net requirements, meaning a Regional IOU's loads in the Region that are not met by the Regional IOU with its own designated power supplies, beginning Fiscal Year 2020 if such service is requested not later than the end of Fiscal Year 2016. At the end of Fiscal Year 2016, the Regional IOUs will elect whether or not to purchase requirements power for Fiscal Years 2020 through 2028. Any requirements power provided by Bonneville under these contracts would be priced at the "New Resources Rate." This rate would in effect reflect the marginal cost to Bonneville of acquiring power to meet the loads plus certain other costs. Bonneville believes that it is unlikely, unless circumstances change, that Regional IOUs will place substantial loads, if any, on Bonneville under the Regional IOU long-term requirements contracts because (i) there is no reason to expect that Bonneville's cost to meet such loads, as reflected in the New Resources Rate, would be significantly lower than the Regional IOUs' cost to meet such loads, (ii) the Regional IOUs are financially motivated to make investments in new generating facilities in order to obtain shareholder returns, (iii) most of the Regional IOUs have state-mandated renewable resource purchase obligations and would have to be assured that such obligations are addressed in any power purchases from Bonneville, (iv) the Regional IOUs would not be able to control directly the terms and costs of the new resources Bonneville would obtain to meet the loads, and (v) the New Resources Rate bears additional costs of statutory rate protection afforded to Preference Customers, thereby likely making the rate uneconomic compared to market alternatives.

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

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

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

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

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

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

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

Credit Risk

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

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

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

In the "California Refund Docket," FERC is examining whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC is examining whether and the extent to which power prices charged to two entities created under California state law to facilitate competitive power markets in the state were "unjust and unreasonable." These entities are the California Power Exchange ("Cal-PX") (which filed for bankruptcy protection and has ceased operations) and the California Independent System Operator ("Cal-ISO"), both of which had obligations to purchase power under the competitive power market structure that California established. Bonneville sold power to the Cal-ISO and the Cal-PX in 2000 and 2001. On April 25, 2012, Bonneville received $73.8 million from Cal-ISO and Cal-PX for the principal amount of outstanding payment obligations to Bonneville for such sales. In litigation arising out of the California Refund Docket, the Ninth Circuit Court ultimately held, in September 2005, that Bonneville was not (under law in effect at the time) subject to FERC authority to order refunds. As a result of the court's ruling, the California Refund Docket cannot result in any FERC-ordered refund liability to Bonneville.

In light of the court ruling, three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric and Southern California Edison ("SCE"), and the California Attorney General on behalf of California Energy Scheduling Resources, a California state agency, filed separate breach of contract claims against Bonneville in the United States Court of Federal Claims ("Court of Federal Claims") in March 2007. Each claim seeks unspecified damages related to Bonneville's power sales into the Cal-PX and Cal-ISO markets. The California parties allege that Bonneville is contractually obligated to provide refunds of amounts received in excess of the mitigated market clearing prices for certain periods in 2000 and 2001, as established by FERC in separate refund proceedings and notwithstanding that FERC has no authority to order refunds against Bonneville for the related sales. The California parties also seek to recover pre-judgment and post-judgment interest and litigation costs. Bonneville estimates that the aggregate contract damages claimed by California parties in the Court of Federal Claims contract litigation arising out of the California Refund Docket are $50 million in specified damages plus an additional amount of unspecified damages. In October 2008, Bonneville filed answers to the various complaints. A trial on the liability issues concluded on August 2, 2010. The parties filed post trial briefs and closing arguments were held in February 2011. On May 2, 2012, the Court of Federal Claims issued an opinion in the trial on liability issues, holding that Bonneville had contracted to limit its power prices in its sales to the California parties and that Bonneville breached its contracts with the California parties by failing to pay refunds for amounts it retained in excess of the mitigated market clearing prices. A damages trial will be scheduled to determine the amount of damages in the event the parties cannot agree on the amount of damages.

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

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

In Fiscal Year 2005, Congress enacted the Energy Policy Act of 2005 ("EPA-2005"), which subjects Bonneville to FERC jurisdiction on a prospective basis for purposes of establishing refund liability. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005." For a description of litigation between SCE and Bonneville arising out of developments in West Coast energy markets in 1999-2000, see "BONNEVILLE LITIGATION—Southern California Edison v. Bonneville Power Administration."

Certain Statutes and Other Matters Affecting Bonneville's Power Services

Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region

The Northwest Power Act requires Bonneville to meet certain firm loads in the Region placed on Bonneville by contract by various Preference Customers and Regional IOUs. Bonneville believes it does not have a statutory obligation to meet all firm loads within the Region. Bonneville is not obligated by law to sell power to a DSI.

Under the Northwest Power Act, when requested, Bonneville must offer to sell to each eligible utility, which includes Preference Customers and Regional IOUs, sufficient power to meet that portion of the utility's Regional firm power loads that it requests Bonneville to meet. The extent of Bonneville's obligation to meet the firm loads of a requesting utility is determined by the amount by which the utility's firm power loads exceed (i) the capability of the utility's firm peaking capacity and energy resources used in operating year 1979 to serve its own loads; and (ii) such other resources as the utility determines, pursuant to its power sales contract with Bonneville, will be used to serve the utility's firm loads in the Region. If Bonneville has or expects to have inadequate power to meet all of its contractual obligations to its customers, certain statutory and contractual provisions allow for the allocation of available power.

As required by law, Bonneville's power sales contracts with Regional utilities contain provisions that require prior notice by the utility before it may use, or discontinue using, a generating resource to serve such utility's own firm loads in the Region. The amount of notice required depends on whether Bonneville has a firm power surplus and whether the Regional utility's generating resource is being added to serve or withdrawn from serving the utility's own firm load. These provisions are designed to give Bonneville advance notice of the need to obtain additional resources or take other steps to meet such load.

Some of Bonneville's Preference Customers and all of the Regional IOUs have generating resources, which they may use to meet their firm loads in the Region. Each of such customers has to identify the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are also included in all existing power sales contracts under which Bonneville has a load following obligation, including under the Long-Term Preference Contracts. The Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load on Bonneville, although Bonneville will serve such new loads at Tier 2 PF Rates, which Bonneville expects will be higher than Tier 1 PF Rates. Bonneville has executed requirements agreements with four Regional IOUs for the period starting in Fiscal Year 2012, but no requirements power will be provided under these agreements until at least Fiscal Year 2020. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Power Sales."

Although Bonneville has contracts to sell firm power to extra-Regional customers, Bonneville is not required by law to offer contracts to meet such customers' firm loads. Similarly, Bonneville provides firm power to certain Federal agencies within the Region; however, Bonneville is not required by law to offer to meet these agencies' firm loads.

<u>Long-Term Preference Contracts</u>. Bonneville currently provides two basic types of service under the Long-Term Preference Contracts. These services are similar to those which Bonneville previously provided to Preference Customers: (i) Slice/Block service, which is an integrated power product combining Slice and Block, and (ii) Load Following service, under which the equivalent of Full Requirements or Partial Requirements service can be obtained from Bonneville. Under Slice/Block, Bonneville commits to provide a Slice of the System product together with fixed blocks of power at designated times. Under Load Following service, Bonneville provides the actual power requirements of the related customer after taking into account generating resources, if any, that the customer has identified, consistent with certain contract conditions, as being used to meet its loads. A customer's net requirements loads, in general, are the customer's loads within its service territory that are served other than with the non-Federal System resources designated by the customer as being used to serve the customer's native loads.

Seventeen separate Preference Customers elected to purchase Slice/Block as the type of service they will receive under their Long-Term Preference Contracts. The remaining Preference Customers have elected to take Load Following service. In aggregate, sales of the Slice component of Slice/Block under the Long-Term Preference Contracts represent about 26.9 percent of Federal System generation. By contrast, Bonneville sold about 22.6 percent of the Federal System generation as Slice under the previous contract methodology. Preliminary forecasts for Fiscal Year 2012 indicate that loads met under Load Following service will be about 3,300 annual average megawatts. Loads met by Slice/Block service will be about 3,800 annual average megawatts in total, half of which is expected to be for the Block portion (1,900 annual average megawatts) and half of which is expected to be for the Slice portion (1,900 annual average megawatts). The forecasts reflect an attempt to predict actual loads that will be met under the specified type of service, which loads vary with weather, economic and other conditions, and in the case of Slice, the actual generation of the Federal System.

All of the Long-Term Preference Contracts for Load Following service subject the customers to a payment commitment under which they are required to pay for power tendered by Bonneville. If a customer's net requirements decline, the customer's purchase obligation from Bonneville is reduced commensurately. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their net requirements. If their net requirements decline, the Block portion is reduced first.

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

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

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

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

A key element of the Long-Term Preference Contracts is the establishment of the Tiered Rates Methodology for periodically determining the applicable PF Preference Rates throughout the term of the new contracts. Bonneville expects to employ two-year rate periods during the term of the Long-Term Preference Contracts. The Tiered Rates Methodology defines the costs that will be allocated to Tier 1 PF Rates and Tier 2 PF Rates: Tier 2 PF Rates recover the costs of meeting Tier 2 Loads while Tier 1 PF Rates recover the costs of the Federal System generating facilities. The costs to be recovered under Tier 1 PF Rates include the costs assigned to power rates for the Net Billed Projects (some Net Billed Project debt service costs are assigned to be recovered in transmission rates), Federal System fish and wildlife costs, electric power conservation programs, transitional power augmentation as discussed above, power benefits to be provided to DSIs (if any), and Residential Exchange Program benefits. Under the Tiered Rates Methodology, a majority of revenues from Bonneville's sales of secondary energy derived from Tier 1 Federal System resources are allocated to non-Slice Tier 1 PF Rates. See "BONNEVILLE LITIGATION—Tiered Rates Methodology Record of Decision."

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

Bonneville provides several approaches for Preference Customers to define the extent, if any, to which Bonneville will meet their Tier 2 Loads. Bonneville provided the customers the ability to rely entirely on Bonneville to meet all such loads throughout the term of the contracts. Bonneville also allows the customers to rely on Bonneville, with specified notice to Bonneville, to meet all or a portion of their Tier 2 Loads for defined multi-year periods through the term of the agreements. Under this approach, a participating Preference Customer may require Bonneville to meet none, all, or designated portions of the customer's Tier 2 Loads. In addition, Bonneville allows customers to make all or portions of their Tier 2 purchases from specified resources or resource pools obtained by Bonneville. This is expected to assist such customers in meeting renewable resource or other requirements or goals.

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

Federal System Load/Resource Balance. In order to determine whether Bonneville will have to obtain additional electric power resources on a planning basis, and to determine the amount of firm power that Bonneville may have to market apart from committed loads, Bonneville periodically estimates the amount of load that it will be required to meet under its contracts.

Bonneville's loads and resources are subject to a number of uncertainties over the coming years. Among these uncertainties are: (i) the level of loads and types of loads placed on Bonneville under the provisions of the Northwest Power Act; (ii) the amount of power purchases, resource acquisitions, and other arrangements that Bonneville will have to make to meet contracted loads; (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions; (iv) the availability of existing generation resources; (v) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional loads; (vi) changes in the regulation of power markets at the wholesale and retail level; (vii) the overall load growth from population changes and economic activity within the Region; and (viii) evolving transmission system needs to provide ancillary services.

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

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

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

Bonneville's resource acquisitions under the Northwest Power Act are guided by a Regional conservation and electric power plan (the "Power Plan") prepared by the Northwest Power and Conservation Council (the "Council"). The governors of the states of Washington, Oregon, Montana, and Idaho each appoint two members to the Council, which is charged under the Northwest Power Act with developing and periodically amending a long range power plan to help guide energy and conservation development in the Region. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations. It addresses risks and uncertainties for the Region's electricity future and seeks a resource strategy that minimizes the expected cost of the Regional power system over the next 20 years. The Power Plan is revised by the Council approximately every five years. On February 10, 2010, the Council released its Sixth Northwest Power Plan (the "Sixth Power Plan"). The Council also develops and periodically amends a fish and wildlife program for the Region. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife."

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

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

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

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

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

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

Short-Term Power Purchases. Bonneville's approach under the Long-Term Preference Contracts is to provide Regional Customers with the opportunity to meet their own incremental loads without facing increased costs for service to their existing loads as a result of such decision. Nonetheless, to the extent that Bonneville assumes incremental load obligations above the existing generating resources of the Federal System, Bonneville must obtain additional electric power. Bonneville believes that, in general, new sources of power should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available, and should have costs that can be offset when hydroelectric power is available. Short-term purchases are the one type of resource that meets incremental load obligations without incurring long-term fixed costs.

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

A short-term purchase strategy can lead to fluctuating revenues and/or revenue requirements. In low water years, Bonneville's revenue requirements could increase as it could be forced to spend a significant amount of money for short-term purchases to meet loads, to the extent that Bonneville had not previously purchased power. In high water years, purchase requirements can be significantly reduced as Bonneville would meet more of its loads with seasonal surplus (secondary) hydroelectric power.

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

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

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

Renewable Energy. Bonneville presently purchases a total of approximately 67 annual average megawatts from various wind energy projects in Wyoming, Oregon, and Washington and small amounts of power from solar photovoltaic projects. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project. This project has not been built. It was originally scheduled to become operational in December 2005, but it is not clear yet whether the site is a viable geothermal resource and the project site is the subject of on-going environmental litigation. Bonneville's expectation of the earliest date for commercial operation has been extended to October 1, 2015.

Acquisition of renewable resource output from specific projects is a potential source of energy to meet forecasted deficits. In addition to any renewable resource acquisitions, Bonneville has launched several initiatives: (1) Bonneville has formed a technical cross agency team dedicated to designing cost-effective means to integrate large amounts of wind power into the Federal System; (2) Bonneville issued a renewable resource information request designed to provide Bonneville and its customers with information on renewable generation available for purchase over the next several years; and (3) Bonneville will continue during Fiscal Year 2012 to provide direct programmatic funding for research and development activities including long-term solar and wind data monitoring.

Residential Exchange Program

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

Under the Residential Exchange Program, Bonneville is to "purchase" power offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology defining the costs that may be included in an exchanging utility's average system cost as the production and transmission costs that an exchanging utility incurs for power. Bonneville is then to offer an identical amount of power for "sale" to the utility for the purpose of "resale" to the exchanging utility's residential users. In reality, no power changes hands. Rather, Bonneville makes cash payments to each exchanging utility in an amount determined by multiplying the utility's eligible residential load by the difference between the utility's average system cost and Bonneville's applicable Priority Firm Exchange Rate (which is a version of the PF Preference Rate adjusted for the costs of statutory rate protection afforded to Preference Customers), if such rate is lower. The costs of the Residential Exchange Program are shown in the Federal System Statement of Revenues and Expenses set forth under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data—Federal System Statement of Revenues and Expenses."

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

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

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

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate, and enhance fish and wildlife resources to the extent they are affected by Federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife in a manner consistent with the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program (the "Council Program"). In addition, in the wake of certain listings of fish species under the ESA as threatened or endangered, Bonneville is financially responsible for expenditures and other costs arising from compliance with the ESA and certain biological opinions prepared by the NOAA Fisheries and the Fish and Wildlife Service in furtherance of the ESA.

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

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

Bonneville's fish and wildlife costs fall into two main categories, "Direct Costs" and "Operational Impacts," both of which are driven primarily by ESA requirements. Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing projects in support of the Council Program, and which include expense and capital components for ESA–related and some non-ESA-related measures that are located at sites away from the Federal System dams; (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps, Reclamation, and Bonneville; and (iii) "Other Entities' operations & maintenance expense ("O&M")," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation for Federal System projects.

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

Bonneville estimates that the aggregate of Direct Costs and Operational Impacts in Fiscal Year 2011 was about $650 million, with $422 million in Direct Costs and $228 million in Operational Impacts. Of the Operational Impacts in Fiscal Year 2011, $71 million was attributable to Replacement Power Purchase Costs and $157 million was attributable to Foregone Power Revenues.

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

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

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

Among other things, the ESA requires that Federal agencies such as Bonneville, the Corps, and Reclamation, take no action that would jeopardize the continued existence of listed species or result in the destruction or adverse modification of their critical habitat. Since 1991, there have been listed as threatened or endangered under the ESA, 13 species of anadromous fish (salmon and steelhead) and two species of resident fish (bull trout and sturgeon) that are affected by operation of the Federal System. It is possible that other species may be listed or proposed for listing in the future. In general, the effect of the listing of the fish species under the ESA, and certain other operating requirements resulting from Bonneville's fish and wildlife obligations under the Northwest Power Act, is that, except in emergencies, the Federal System is now operated for power production only after meeting needs for flood control and the protection of ESA-listed fish.

In connection with the listing of these species, NOAA Fisheries has prepared certain biological opinions addressing Federal System hydroelectric dam operations with respect to the anadromous listed species, and the Fish and Wildlife Service has developed biological opinions with respect to the resident listed species. These biological opinions provide information that Bonneville, the Corps, and Reclamation can use to ensure that their actions with respect to the operation of the Federal System satisfy the ESA. By acting consistently with the biological opinions, Bonneville, the Corps, and Reclamation demonstrate that jeopardy to listed species is being avoided. The implementation of the ESA with respect to the Federal System has been and is the subject of litigation and judicial review.

Operation of the Federal System hydroelectric dams consistent with the ESA has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise run through turbines to generate electricity may be spilled to aid in downstream fish migration. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration. Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these changes, under certain water conditions, Bonneville has had to, and may have to, purchase additional energy for the fall and winter to meet load commitments that would otherwise have been met with the hydroelectric system. In addition, the flow changes have meant that Bonneville has had comparatively more surplus energy to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System in conformance with the biological opinions and the Council Program, as in effect as of the beginning of Fiscal Year 2000, decreased Federal System generation capability by about 1,000 annual average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the NOAA Fisheries biological opinion in 1995. The consequences of this and similar ESA-related decrements in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

These ESA listings and related actions to protect listed species and their habitat have resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville's fish and wildlife mitigation costs increased from about $20 million in Fiscal Year 1981 to $150 million in Fiscal Year 1991. After the issuance of the first biological opinion affecting Federal System operations, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in Fiscal Year 1995. Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council Program, discussed below. Bonneville is also providing funding under the funding agreements entered into with certain tribes and the states of Idaho, Montana, and Washington. See "—The 2008 Columbia River System Biological Opinion, the 2010 Supplemental Columbia River System Biological Opinion and Related Developments."

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

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

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

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

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

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

In June 2010, NOAA Fisheries issued a supplemental record and a decision to supplement the 2008 Columbia River System Biological Opinion with the Management Plan and certain other information addressing new and pertinent scientific information. As so supplemented, the 2008 Columbia River System Biological Opinion is referred to by NOAA Fisheries as the "2010 Supplemental Columbia River System Biological Opinion." A number of interests have challenged the 2010 Supplemental Columbia River System Biological Opinion in litigation. On August 2, 2011, the Oregon Federal District Court upheld the 2010 Supplemental Columbia River System Biological Opinion through 2013, but ordered that NOAA Fisheries issue a new or supplemental Columbia River System Biological Opinion by January 1, 2014 for the period 2014 through 2018 that identifies specific mitigation measures and provides better scientific support for the conclusion that those measures will avoid jeopardy than was provided for such period in the 2010 Supplemental Columbia River System Biological Opinion. The Oregon Federal District Court also ordered that NOAA Fisheries conduct spring and summer spill operations in a manner consistent with the annual spill orders that have been in effect since 2006. See "BONNEVILLE LITIGATION—ESA Litigation—Columbia River."

The Columbia Basin Fish Accords. In concert with the development of the 2008 Columbia River System Biological Opinion, Bonneville, the Corps, and Reclamation, and a number of Regional interests including five tribes, an inter-tribal association, and the states of Montana and Idaho, signed a number of separate agreements in the spring of 2009 to assure long-term fish and wildlife funding with respect to the Federal System. In September 2009, the Federal agencies and the State of Washington signed an agreement addressing the Columbia River estuary. The foregoing agreements, collectively known as the Columbia Basin Fish Accords, are designed to improve habitat and strengthen fish stocks in the Columbia River Basin over the next ten years. Most of the funding will be provided by Bonneville. Under the agreements, the tribes and states commit to accomplishing biological objectives with the funds, linked to meeting the Federal agencies' statutory requirements.

Under the Columbia Basin Fish Accords, Bonneville has committed to make available roughly $994 million over the ten-year period ending September 30, 2018. Bonneville estimates that roughly 60 percent of its proposed funding commitments in the agreements would be for new work required for implementation of the 2008 Columbia River System Biological Opinion and otherwise agreed to in furtherance of Federal statutory fish and wildlife purposes such as the Northwest Power Act. The remaining amounts committed to in these agreements affirm the continuation of activities for fish and wildlife in furtherance of the ESA and Northwest Power Act that would otherwise face funding uncertainty after Fiscal Year 2009. While the Columbia Basin Fish Accords provide funding assurances to implement many actions under the 2008 Columbia River System Biological Opinion to protect listed species under the ESA, the agreements also assure funding for other fish restoration efforts, including efforts under the Northwest Power Act.

Under certain of the agreements, the participating tribes and states agree that the Federal government's requirements under the ESA, the Federal Water Pollution Control Act, and the Northwest Power Act are satisfied as to the identified Federal System hydropower projects in the Snake River and Columbia River drainages for ten years beginning April 2008. The 2009 agreement with Washington provides for similar commitments regarding the ESA. The parties to the agreements also agreed that they will work together to support the agreements in all appropriate venues. The agreements would also specifically resolve, for these parties, ESA litigation regarding Federal System hydropower projects in the Snake River and Columbia River drainages now pending before the Oregon Federal District Court. Bonneville also believes that the agreements have helped fulfill the court's requirement that the parties increase collaboration in preparing the 2008 Columbia River System Biological Opinion. The agreements also provide a higher level of assured long-term funding, which was a concern raised by the court in reviewing past biological opinions.

Incremental Costs and Consequences of the 2010 Supplemental Columbia River System Biological Opinion. It is difficult to predict the aggregate increased cost to Bonneville that will arise from the 2010 Supplemental Columbia River System Biological Opinion (which incorporates the 2008 Columbia River System Biological Opinion). Many measures in the 2010 Supplemental Columbia River System Biological Opinion have been implemented, are currently being implemented, or would otherwise be implemented, including under the Columbia Basin Fish Accords. Certain measures involve long-term costs or expenses that are difficult to predict. Qualified by the foregoing and other uncertainties, Bonneville estimates that the 2010 Supplemental Columbia River System Biological Opinion and the Columbia Basin Fish Accords will, in aggregate, increase the expense portion of Bonneville's cost of service by approximately $100 million per year over the ten-year term of the agreements, and increase power rates (all other things being equal) by about four percent, in each case when compared to Fiscal Year 2008 rate levels. This amount does not include Bonneville's capitalized repayment responsibility for the appropriated costs of the structural modifications described above. As noted above, the capital costs will be included for recovery in Bonneville's rates as a Federal System appropriation repayment responsibility to the United States Treasury as and when the related facilities are placed in service and then will be depreciated over their expected useful lives. The expected cost in Fiscal Year 2012 and 2013 of the 2010 Supplemental Columbia River System Biological Opinion was incorporated into Bonneville's power rates for the 2012-2013 Rate Period.

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

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

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

Bonneville believes that the costs to achieve measures for stream flow, fish hatchery and habitat improvements, and structural changes at various dams could substantially increase its cost of power from these related dams. However, because these costs are likely to be blended in with all of the other financial obligations and revenue streams that Bonneville manages, Bonneville does not expect there to be a significant impact upon overall power rates.

<u>Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville</u>. In 1995, the United States Treasury, the Office of Management and Budget, DOE, and other agencies agreed to provide for certain Federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision authorizes Bonneville to exercise its Northwest Power Act authority to implement fish and wildlife mitigation on behalf of all of a Federal System project's authorized purposes under Federal law; not just those relating to the delivery of generation and transmission services to customers, but also non-power purposes such as irrigation, navigation, and flood control. At the end of the fiscal year, Bonneville is required to recoup (*i.e.*, take a credit for) the portion allocated to non-power purposes. Included in this credit are Direct Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was about $99 million, $123 million, and $85 million in Fiscal Years 2009, 2010, and 2011, respectively. Forecasts of these 4(h)(10)(C) credits are treated as revenues in Bonneville's ratemaking process. At the close of each fiscal year, they are applied against Bonneville's payments to the United States Treasury. The 4(h)(10)(C) credits are initially taken based on estimates and are subsequently modified to reflect actual data. An important cost that may be recouped under section 4(h)(10)(C) is that of Replacement Power Purchases necessitated by the loss of generation arising from certain changes to hydroelectric system operations for the benefit of fish and wildlife. These costs occur annually and are highest in low water years when, historically, the output of the hydro-system is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

<u>Council's Fish and Wildlife Program</u>. In 2000, the Council revised and adopted a Columbia River Basin Fish and Wildlife Program (the "2000 Program"). The Council amended 57 sub-basin plans into the 2000 Program in 2003 with "mainstream amendments" meant primarily to address mitigation issues related to operation of the Federal System. In 2005, the Council amended the 2000 Program to help focus mitigation actions on overcoming environmental limitations to increased fish and wildlife populations. The 2000 Program emphasizes an ecosystem approach to rebuilding fish and wildlife in the Columbia River basin. The Council sets forth an "integrated program" that integrates mitigation recommendations from both the 2000 Program created under the Northwest Power Act and recovery actions needed for Bonneville to comply with the ESA. The Integrated Program Costs are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General." For the 2007-2009 Rate Period, Bonneville originally forecasted an average expense accrual budget level of $143 million per year for the expense portion of the integrated program, and $36 million per year for the capital portion. With the successful conclusion of the Columbia Basin Fish Accords and the expected implementation of the 2010 Supplemental Columbia River System Biological Opinion and the Willamette River Project Biological Opinion, the integrated program expense spending grew to $221 million in Fiscal Year 2011. Fiscal Year 2012 expenses and capital program investments are forecast to be $237 million and $60 million, respectively.

Bonneville cannot provide assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System, including measures resulting from current and future listings under the ESA, current and future biological opinions or amendments thereto, future Council programs or amendments thereto, or litigation relating to the foregoing.

Power Rates for Fiscal Years 2012 through 2013

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

<u>PF Preference Rates</u>. Most of Bonneville's power sales are made to Preference Customers to meet their net requirements under specified types of service: Block/Slice and Load Following. These power products and services are provided at Bonneville's lowest, statutorily-designated, cost-based power rate class, the PF Preference Rates. PF Preference Rates in general reflect the cost of resources and other services provided to serve the Preference Customers' net requirements loads and Residential Exchange Program loads and, except with respect to the rate for Slice ("PF Slice Rate"), reflect the benefit of revenues from sales by Bonneville of seasonal surplus (secondary) energy. In the case of

the Slice product, the participating customers receive a percentage share of the seasonal surplus energy of the Federal System and hence the PF Slice Rate does not reflect the revenues Bonneville receives from its marketing of seasonal surplus energy. The PF Slice Rate also does not incorporate the costs or risks associated with power supply and power purchase costs, which are borne directly by Slice customers. While each of the foregoing services is provided under PF Preference Rate schedules, the applicable rate level depends on Bonneville's rate design and specific costs to provide the related service.

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

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

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

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

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

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

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

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

Recovery of Stranded Power Function Costs

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

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

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

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

Under EPA-2005, FERC was granted authority to require that the rates for transmission service that Bonneville provides to itself be comparable to the rates it charges others. The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act but must be balanced with them. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville, notwithstanding the enactment of EPA-2005. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

TRANSMISSION SERVICES

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately and publicly owned utilities, power marketers, power generators, and others. Transmission Services earned about $740 million in revenues from the sale of transmission and related services, or roughly 23 percent of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2011.

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

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

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System that is owned, operated, and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-Federal power resources. The Federal Transmission System is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 300 substations and other transmission facilities that are located in Washington, Oregon, Idaho, and portions of Montana, Wyoming, and northern California. The Federal Transmission System includes an integrated network for service within the Pacific Northwest ("Network"), and approximately 80 percent of the northern portion (north of California and Nevada) of the combined Southern Intertie, the primary bulk transmission link between the Pacific Northwest and the Pacific Southwest. The Southern Intertie consists of three high voltage Alternating Current ("AC") transmission lines and one Direct Current ("DC") transmission line and associated facilities that interconnect the electric systems of the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4,800 megawatts of capacity, and in the south to north direction is 3,675 megawatts of capacity. The rated transfer capability of the DC line in both directions is 3,100 megawatts. The actual operating transfer capability can vary (or reliability transfer capability) by generation patterns, weather conditions, load conditions, and system outages.

The Federal Transmission System is used to deliver Federal and non-Federal power between resources and loads within the Network, and to import and export power from and to adjacent regions. Bonneville's Transmission Services provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Services; entities that buy and sell non-Federal power in the Region such as Regional IOUs, Preference Customers, extra-Regional IOUs, independent power producers, aggregators, and power marketers; in-Region purchasers of Federal System power such as Preference Customers and DSIs; and generators, power marketers, and utilities that seek to transmit power into, out of, or through the Region.

Bonneville constructed the Federal Transmission System and is responsible for its operation, maintenance, and expansion to maintain electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by internal, regional, and national reliability practices. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005" for a discussion of statutory provisions relating to reliability. Bonneville continually monitors the system and evaluates cost-effective reinforcements needed to maintain electrical stability and reliability of the system on a long-term planning basis. A number of conditions, actions, and events could affect the operating transfer capability and diminish the capacity of the system. For example, operating conditions such as weather, system outages, and changes in generation and load patterns may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of the system's users, including Bonneville's Power Services. To assure that the system is adequate to meet transmission needs, Transmission Services evaluates system performance to determine whether or not to make transmission infrastructure investments.

Bonneville focuses its transmission infrastructure efforts on transmission projects needed to maintain reliability and new transmission projects that will provide additional, long-term firm transmission service for those seeking new transmission service in the Region, especially those developing new power generation projects, primarily wind generation, both inside and outside the Region. Bonneville's current transmission system investment plan calls for Bonneville to make investments in Fiscal Years 2012 through 2017 averaging about $604 million annually. To finance the foregoing investments, Bonneville expects to use United States Treasury borrowing, reserves, and advance payments from generation integration and transmission customers. Bonneville also expects to use long-term, capitalized lease-purchase arrangements to acquire transmission infrastructure facilities as a means of reducing the pressure on Bonneville's United States Treasury borrowing authority.

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

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

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

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

Bonneville's transmission system investment plan is subject to change as Bonneville is unable to predict the cost of new investments for the integration of new generation or to meet customers' new transmission service requests, the amount that customers will actually commit to on terms acceptable to Bonneville, or the extent to which Bonneville will fund such investments through customer advances of funds, borrowing from the United States Treasury, or third-party debt, such as lease-purchases. For discussion of applicability of FERC's cost allocation methodology under Order 1000, see "—Bonneville's Participation in a Regional Transmission/Planning Organization."

With respect to Bonneville's lease-purchase program, Bonneville entered into a long-term, capitalized lease-purchase agreement with Northwest Infrastructure Financing Corporation ("NIFC") in 2003 for a large transmission line project located in Washington state. NIFC issued about $120 million in bonds to fund construction of the project. The bonds are secured solely by NIFC's pledge of Bonneville's lease payments under the project lease.

In June 2007, Bonneville entered into a master lease agreement with Northwest Infrastructure Financing Corporation II ("NIFC II") (amended and restated as of December 9, 2010) under which Bonneville entered into lease-purchase commitments to lease $90 million in aggregate Federal Transmission System replacements and improvements. Under the master lease arrangement, Bonneville's lease-purchase payments are pledged to the payment of bank loans entered into by NIFC II. Proceeds of the bank loans were used to fund the acquisition, construction, installation, and equipping of the leased facilities. Bonneville's lease payments are not conditioned on the completion, suspension, or termination of the related projects.

As described in the Official Statement, the Issuer and NIFC II will enter into an agreement in which NIFC II will sell its interests in the NIFC II facilities to the Issuer. Coincidentally, the Issuer and Bonneville will execute a lease purchase agreement (the "Lease Agreement") under which the Issuer will lease such facilities (the "Project") to Bonneville and pledge Bonneville's lease rental payment to the payment of debt service on the 2012 Bonds. The Issuer will use the proceeds from the sale of the 2012 Bonds to fund the acquisition of the transmission facilities from NIFC II. See the Official Statement under "INTRODUCTORY STATEMENT" and "PURPOSE OF ISSUANCE AND USE OF PROCEEDS." The 2012 Bonds will be secured solely by Issuer's pledge of Bonneville's lease rental payments under the Lease Agreement.

Subsequent to the entry into the NIFC II master lease arrangement Bonneville entered into four separate master lease agreements with Northwest Infrastructure Financing Corporation III ("NIFC III"), Northwest Infrastructure Financing Corporation IV ("NIFC IV"), Northwest Infrastructure Financing Corporation V ("NIFC V"), and Northwest Infrastructure Financing Corporation VI ("NIFC VI") under which Bonneville has entered into lease-purchase commitments for $528.7 million in aggregate Federal Transmission System replacements and improvements. These latter lease-purchase arrangements are similar to the NIFC II master lease and bank loan arrangement described above. The principal amounts associated with all of the banks' loans described above are included in Federal System audited financial statements as "Non-Federal Debt" and and the principal amounts associated with the 2012 Bonds will be included in Federal System audited financial statements as "Non-Federal Debt." As part of Bonneville's annual budget submitted to Congress for Fiscal Year 2013, Bonneville forecast that expenditures from funds provided under lease-purchase agreements will average about $89 million annually over Fiscal Years 2012-2017. The budget forecasts are not binding on Bonneville and the actual value could differ, perhaps substantially, from such estimates depending on capital spending in such years and other factors.

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

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

While Bonneville is not generally subject to the FPA, Bonneville is a "transmitting utility" under EPA-1992. Therefore, FERC may order Bonneville to provide others with transmission access over the Federal transmission system facilities. FERC also may set the terms and conditions for such FERC-ordered transmission service. However, the transmission rates for FERC-ordered transmission under EPA-1992 are governed only by Bonneville's other applicable laws, except that no such rate shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by FERC. Based on the legislative history relating to the provisions of EPA-1992 applicable to Bonneville, Bonneville's General Counsel is of the opinion that Bonneville's rates for FERC-ordered transmission services under sections 211 and 212 are to be established by Bonneville, rather than by FERC, and are reviewed by FERC through the same process and using the same statutory requirements of the Northwest Power Act as are otherwise applicable to Bonneville's transmission rates. In addition, with respect to Bonneville's ability to recover its transmission costs through its transmission rates, it is the opinion of Bonneville's General Counsel that the EPA-2005 provisions relating to Bonneville's transmission rates would not adversely affect Bonneville's authority and obligation to recover in full the costs of providing transmission service through its transmission rates. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

In 1996, FERC issued Order 888 to promote competition in wholesale power markets. Among other things, Order 888 established a *pro forma* tariff providing the terms and conditions for non-discriminatory open access transmission service, and required all regulated or jurisdictional utilities to adopt the tariff. Order 888 also included a reciprocity provision under which jurisdictional utilities must grant open access transmission services to non-jurisdictional (i.e., unregulated) utilities if the non-jurisdictional utility offers open access in return, either through bilateral contracts or by (i) submitting to FERC for its approval an open access transmission tariff that substantially conforms or is superior to the *pro forma* tariff and (ii) adopting transmission rates for third parties that are comparable to the rates the non-jurisdictional utility applies to itself. FERC issued "Order 890" in February 2007, which further supported Order 888's aims, emphasizing increased transmission access and transparency and promotion of transmission utilization. Bonneville is a non-jurisdictional utility.

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

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

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

In April 1996, FERC issued “Order 889” and more recently, in October 2008, “Order 717,” each setting forth the “standards of conduct” for jurisdictional utilities that are transmission providers and have a power-marketing affiliate or function. In general, these standards of conduct are intended to assure that wholesale power marketers that are affiliated with a transmission provider do not obtain unfair market advantage by having preferential access to information regarding the transmission provider’s transmission operations. Although Bonneville is not subject to Orders 889 and 717, non-jurisdictional utilities must adhere to it in order to obtain reciprocity. Therefore, in the 1990s Bonneville separated its transmission and power functions into separate business units. Bonneville continued to voluntarily adapt its operations to comply with FERC’s standards of conduct provisions. It currently operates in accordance with the standards of conduct set forth in Order 717.

Bonneville’s Transmission and Ancillary Services Rates

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

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

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

Bonneville's Participation in a Regional Transmission/Planning Organization

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

Bonneville is currently a member of "ColumbiaGrid," a regional planning organization comprising eight western transmission owners with balancing authority areas in the Region. ColumbiaGrid is not an "RTO" under FERC policies since ColumbiaGrid has a relatively restricted scope of operations. ColumbiaGrid focuses on coordinating Regional transmission planning and expansion, assisting participating utilities in meeting their transmission reliability obligations, and operating an information system to provide power marketers and others with information about transmission system operations. It is possible that in the long run ColumbiaGrid would have increased operational control of the Region's transmission assets and take an increased role in providing transmission service, including through the operation of transmission markets and market monitoring. Whether ColumbiaGrid's scope of operations evolves to include new functions will be determined by the participating utilities.

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

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

FERC has provided further regional transmission planning direction in its "Order 1000" issued on July 21, 2011. Order 1000 requires, among other things, that jurisdictional utilities participate in certain regional transmission planning processes and in regional and interregional cost allocation methodologies for transmission projects. Order 1000 by its terms does not apply to non-jurisdictional utilities, such as Bonneville, but FERC has strongly encouraged non-jurisdictional utilities to participate and comply. FERC, in Order 1000, stated that it might exercise its authority under section 211A of the FPA to require non-jurisdictional utilities' compliance with Order 1000's provisions if voluntary compliance is not forthcoming.

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

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

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

MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards

Bonneville is required to periodically review and, as needed, to revise rates for power sold and transmission services provided in order to produce revenues that recover Bonneville's costs, including its payments to the United States Treasury. The Northwest Power Act incorporates the provisions of other Bonneville organic statutes, including the Transmission System Act and the Flood Control Act. The Transmission System Act requires, among other things, that Bonneville establish its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment to the United States Treasury. Substantially the same requirements are set forth in the Flood Control Act.

Bonneville Ratemaking Procedures

The Northwest Power Act contains specific ratemaking procedures used to develop a full and complete record supporting a proposal for revised rates. The procedures include publication of the proposed rate(s), together with a statement of justification and reasons in support of such rate(s), in the Federal Register and a hearing before a hearing officer. The hearing provides an opportunity to refute or rebut material submitted by Bonneville or other parties and also provides a reasonable opportunity for cross-examination, as permitted by the hearing officer. Upon the conclusion of the hearing, the hearing officer certifies a formal hearing record (including hearing transcripts, exhibits, and such other materials and information as have been submitted during the hearing) to the Bonneville Administrator. This record provides the basis for the Administrator's final decision, which must include a full and complete reasoning in support of the proposed rate(s).

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

Rates established by Bonneville under the Northwest Power Act may become effective only upon confirmation and approval by FERC, although FERC may grant interim approval of Bonneville's proposed rates pending FERC's final confirmation and approval.

FERC's review under the Northwest Power Act of Bonneville's power rates and transmission rates involves three standards set out in the Northwest Power Act. These standards require FERC to confirm and approve these Bonneville rates based on findings that such rates: (i) are sufficient to assure repayment of the Federal investment in the Federal System over a reasonable number of years after first meeting Bonneville's other costs; (ii) are based on Bonneville's total system costs; and (iii) insofar as transmission rates are concerned, equitably allocate the costs of the Federal Transmission System between Federal and non-Federal power utilizing such system. FERC does not, however, review Bonneville's rate design or the cost allocation for rates for firm power and Regional non-firm energy.

Upon reviewing Bonneville's power rates, FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a power rate in lieu of a proposed rate that FERC finds does not meet the applicable standards. In the opinion of Bonneville's General Counsel, if FERC were to reject a proposed Bonneville power rate, FERC would be limited to remanding the proposed rate to Bonneville for further proceedings as Bonneville deems appropriate. On remand, Bonneville would reformulate the proposed rate to comply with the statutory ratemaking standards. If FERC were to have given Bonneville interim approval, Bonneville may be required to refund the difference between the interim rate charged and any such final, FERC-approved rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

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

Judicial Review of Federal Energy Regulatory Commission Final Decision

FERC's final approval of a proposed Bonneville rate under the Northwest Power Act is a final action subject to direct, exclusive review by the Ninth Circuit Court, if challenged. Suits challenging final actions must be filed within 90 days of the time such action is deemed final. The record upon review by the court is limited to the administrative record compiled in accordance with the Northwest Power Act.

Unlike FERC, the court reviews all of Bonneville's ratemaking for conformance with all Northwest Power Act standards, including those ratemaking standards incorporated by reference in the Northwest Power Act. In the opinion of Bonneville's General Counsel, the court lacks the authority to establish a Bonneville rate. Upon review, the court may either affirm or remand a rate to FERC or Bonneville, as appropriate. On remand, Bonneville would reformulate the remanded rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville may be subject to refund obligations if the reformulated rate were lower than the remanded rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Power Customer Classes

The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (i) to Preference Customers and certain Federal agency customers; (ii) to DSIs; (iii) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program; and (iv) as requested, to meet the net requirements of investor-owned utilities. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for power sold to these respective customer classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

Other Firm Power Rates

Bonneville's rates for other firm power sales within the Region are based on the cost of such resources as Bonneville may decide are applicable to such sales. Bonneville also sells similarly priced surplus firm power outside the Northwest, primarily to California, under short-term power sales that allow for flexible prices, or under long-term contract rates.

Surplus Energy

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

Limitations on Suits against Bonneville

Suits challenging Bonneville's actions or inaction may only be brought pursuant to certain Federal statutes that waive sovereign immunity. These statutes limit the types of actions, remedies available, procedures to be followed, and the proper forum. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville is a judgment for money damages. See "BONNEVILLE LITIGATION" for information regarding pending litigation seeking to compel or restrain action by Bonneville.

Laws Relating to Environmental Protection

Bonneville must comply with the National Environmental Policy Act ("NEPA"), which requires that Federal agencies conduct an environmental review of a proposed Federal action and prepare an environmental impact statement if the action proposed may significantly affect the quality of the human environment. NEPA may require that Bonneville follow statutory procedures prior to deciding whether to implement an action. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Toxic Substance Control Act ("TSCA"), and applicable state statutes and regulations, as well as amendments thereto, may result in Bonneville incurring unplanned costs to investigate and clean up sites where hazardous substances have been released or disposed of. Bonneville has been identified as one of several potentially responsible parties at two sites. Bonneville's environmental protection costs at one site are approximately $400,000 to date. Bonneville has not committed to any cleanup at this time pending a Record of Decision in 2012, but Bonneville's additional environmental protection costs at the site are not expected to exceed $100,000. Bonneville's potential liability for environmental protection costs at a second site is uncertain at this time, but is not expected to exceed $10 million.

Energy Policy Act of 2005

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

(i) EPA-2005 amends the FPA to authorize FERC to require an unregulated transmitting utility (a term that includes Bonneville) to provide transmission services at rates comparable to those the utility charges itself, and on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. On December 7, 2011, FERC, invoking this authority, rejected Bonneville's Interim Policies, on the basis it did not provide comparable transmission service, and ordered Bonneville to file tariff revisions addressing the comparability concerns raised in the proceeding. Bonneville filed amended tariff language on March 6, 2012, in response to FERC's ruling. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System." FERC has not otherwise exercised its authority under this provision.

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

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

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue and enforce mandatory reliability rules that cover all users, owners, and operators of the bulk power system. The mandatory reliability standards apply to Bonneville, but EPA-2005 expressly states that neither the ERO nor FERC are authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. Monetary penalties for violation of the standards may be assessed by the ERO and approved by FERC, but it has not yet been determined whether Congress authorized monetary penalties to be imposed on federal agencies, such as Bonneville.

2010 Dodd-Frank Act and Bonneville

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

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

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

Other Applicable Laws

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

Columbia River Treaty

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

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

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

The United States Entity and Canadian Entity have consulted on terms for possible disposal of portions of the Canadian Entitlement in the United States. Direct disposal of the Canadian Entitlement in the United States was authorized by the executive branches of the United States and Canadian governments through an exchange of diplomatic notes, which occurred in 1999.

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

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of Bonneville's current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in or submitted to Congress have included privatizing the Federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at Federal hydroelectric projects, studying the removal of certain Federally-owned dams of the Federal System, placing caps on Bonneville's authority to incur certain types of capitalized costs, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates, and limiting Bonneville's ability to incur new third-party debt.

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

Bonneville is a Federal agency. It is subject to direction or guidance in a number of respects from the United States Office of Management and Budget, DOE, FERC, the United States Treasury and other Federal agencies. Bonneville is frequently the subject of, or would otherwise be affected by, various executive and administrative proposals. Bonneville is unable to predict the content of future proposals; however, it is possible that such proposals could materially affect Bonneville's operations and financial condition.

Climate Change

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

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

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

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

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

Wind Generation Development and Integration into the Federal Transmission System

Wind Generation Development and Integration

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

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

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

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

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

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

Over-generation from High Water and High Wind

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

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

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

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

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

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

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

Starting in April 2012, Bonneville applied its Oversupply Management Protocol to displace non-Federal generation. Through July 18, 2012, Bonneville has displaced 46,599 megawatt hours of generation resulting in eligible displacement costs of approximately $3 million. Bonneville has compensated non-Federal generators for about $1 million of the eligible displacement costs to date and expects to provide credits for the additional $2 million of eligible displacement costs on future transmission bills of the non-Federal generators in the month following the displacement. Continued runoff and changing weather conditions present the possibility of oversupply events through September 2012. Bonneville estimates that on an expected value basis, it will compensate non-Federal generators about $12 million per year in aggregate, on average, to reduce electricity generation if oversupply events continue to occur. Under extreme conditions (very low probability), compensation could exceed $50 million in a given year. Fiscal Year 2012 displacement compensation costs resulting from implementation of the Oversupply Management Protocol will be temporarily covered by Transmission Services' reserves until Bonneville establishes new rates to recover such costs and reimburse Transmission Services' reserves. Bonneville is considering allocating the displacement compensation costs equally between the Federal System users (primarily Preference Customers) and the compensated non-Federal generators within Bonneville's balancing authority area. Bonneville's proposal does not address any claims for damages associated with Bonneville's implementation of its Interim Policies.

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

Prior to 1974, Congress annually appropriated funds for the payment of Bonneville's obligations, including working capital expenditures. Under the Transmission System Act, Congress created the Bonneville Fund, a continuing appropriation available to meet all of Bonneville's cash obligations.

All receipts, collections, and recoveries of Bonneville in cash from all sources are now deposited in the Bonneville Fund. These include revenues from the sale of power and other services, trust funds, proceeds from the sale of bonds by Bonneville to the United States Treasury, any appropriations by Congress for the Bonneville Fund, and any other Bonneville cash receipts.

Bonneville is authorized to make expenditures from the Bonneville Fund without further appropriation and without fiscal year limitation if such expenditures have been included in Bonneville's annual budget to Congress. However, Bonneville's expenditures from the Bonneville Fund are subject to such directives or limitations as may be included in an appropriations act. Bonneville's annual budgets are reviewed and may be changed by the DOE and subsequently by the United States Office of Management and Budget. The Office of Management and Budget, after providing opportunity for Bonneville to respond to proposed changes, includes Bonneville's budget in the President's budget submitted to Congress.

The existence of the Bonneville Fund also enables Bonneville to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount of cash in the Bonneville Fund and available borrowing authority. Pursuant to the Project Act and other law, Bonneville has broad authority to enter into contracts and make expenditures to accomplish its objectives.

No prior budget submittal, appropriation, or any prior Congressional action is required to create such obligations except in certain specified instances. These include construction of transmission facilities outside the Region, construction of major transmission facilities within the Region, construction of certain fish and wildlife facilities, condemnation of operating transmission facilities, and acquisition of certain major generating or conservation resources.

The Federal System Investment

The total cost of the multipurpose Corps and Reclamation projects that are part of the Federal System is allocated among the purposes served by the projects, which may include flood control, navigation, irrigation, municipal and industrial water supply, recreation, the protection, mitigation, and enhancement of fish and wildlife, and the generation of power. The costs allocated to power generation from the Corps and Reclamation projects as well as the cost of the transmission system prior to 1974 have been funded through appropriations. The capital costs of the transmission system since 1974 and certain capital conservation and fish and wildlife costs since 1980 have been funded in great part through the use of Bonneville's borrowing authority with the United States Treasury.

Bonneville is required by statute to establish rates that are sufficient to repay the Federal investment in the power facilities of the Federal System within a reasonable period of years. The statutes, however, are not specific with regard to directives for the repayment of the Federal System investment, including what constitutes a reasonable period of years. Consequently, the details of the repayment policy have been established through administrative interpretation of the basic statutory requirements. The current administrative interpretation is embodied in the United States Secretary of Energy's directive RA 6120.2. The directive provides that Bonneville must establish rates that are sufficient to repay the Federal investments within the average expected service life of the facility or 50 years, whichever is less. Bonneville develops a repayment schedule both to comply with investment due dates and to minimize costs over the repayment period. Costs are minimized, in accordance with the United States Secretary of Energy's directive RA 6120.2, by repaying the highest interest-bearing investments first, to the extent possible. This method of determining the repayment schedule would result in some investments being repaid before their due dates, while assuring that all investments will be repaid by their due dates. As of September 30, 2011, Bonneville had repaid $10.4 billion of principal of the Federal System investment and has $4.3 billion principal amount outstanding with regard to such appropriated investments and $2.9 billion principal outstanding in bonds issued by Bonneville to the United States Treasury.

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

Bonneville Borrowing Authority

Bonneville is authorized to issue and sell to the United States Treasury, and to have outstanding at any one time, up to $7.7 billion aggregate principal amount of bonds. Of the $7.7 billion in borrowing authority that Bonneville has with the United States Treasury, $2.9 billion of bonds were outstanding as of September 30, 2011. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 annual average megawatts. Of the $7.7 billion in United States Treasury borrowing authority, $1.25 billion is available for electric power conservation and renewable resources, including capital investment at the Federal System hydroelectric facilities owned by the Corps and Reclamation, and $6.45 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable Federal Government institutions at the time of issuance. As of September 30, 2011, the interest rates on the outstanding bonds ranged from 1.4 percent to 6.4 percent with a weighted average interest rate of approximately 4.2 percent. The original terms of the outstanding bonds vary from 4 to 30 years. The term of the bonds is limited by the average expected service life of the associated investment: 35 years for transmission facilities, 45 years for Corps and Reclamation capital investments, up to 20 years for conservation investments, and 15 years for fish and wildlife projects. Bonds can be issued with call options.

Banking Relationship between the United States Treasury and Bonneville

Effective April 30, 2008, Bonneville entered into an Obligation Purchase Memorandum of Understanding ("Obligation Purchase MOU") establishing a new banking arrangement governing the terms by which Bonneville borrows from the United States Treasury. Formerly, there was no overarching formal documentation of the terms under which the United States Treasury would lend funds to Bonneville; rather, the banking arrangement was more informal with borrowings made on the basis of administrative practice evolved over more than 30 years. The new banking arrangement provides a process and methodology for establishing interest rates, various types of credit facilities, the terms for several types of prepayment rights, the documentation requirements for requesting advances and rescinding advances requests, and a number of other administrative details. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, as amended in Fiscal Year 2009, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating advances can be made available on as short as one day's notice and have a maximum repayment period of one year, although Bonneville may extend the maturities an additional year by exercising certain rights that would re-establish applicable interest rates. Nothing in the new banking arrangement increases the statutory limit on the $7.7 billion aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time.

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

Bonneville's Capital Program

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

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

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

Conservation expenditures in Fiscal Years 2009, 2010, and 2011 were about $18 million, $58 million, and $162 million, respectively. Bonneville forecasts that annual conservation expenditures will average about $131 million per year in Fiscal Years 2012-2017. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies—Electric Power Conservation."

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

There is substantial uncertainty in forecasting capital program needs.

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

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

Energy Northwest Net Billing Agreements

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 other project, the Columbia Generating Station, was completed and is operating. The original operating license of Columbia Generating Station was due to expire on December 20, 2023. On May 22, 2012, the Nuclear Regulatory Commission granted license extension of Columbia Generating Station and extended the licensed period of operation for an additional 20 years (through December 20, 2043). There are approximately $5.56 billion, as of September 30, 2011, of outstanding bonds for the Energy Northwest Net Billed Projects, and Bonneville secures such bonds through the Net Billing Agreements.

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (as amended, the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its ownership share of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (as amended, the "Project 3 Net Billing Agreements," which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Under the Net Billing Agreements, each Participant assigned its share of the capability of the Net Billed Project to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project. This Issuer is a Participant in each of Project 1, Project 3 and Columbia Generating Station, and has a Participant's Share of such projects in the amount of .25 percent, .21 percent and .05 percent, respectively.

Under the Net Billing Agreements, in payment for the share of the capability of each Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement. 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 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. Aggregate debt service for Columbia Generating Station is estimated by Energy Northwest to be about $3.5 billion for the period of Energy Northwest Fiscal Years (July 1st – June 30th) 2012 – 2024. In August 2012, Energy Northwest expects to issue an additional $700 million in bonds for

Columbia Generating Station to finance the Uranium Program. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Energy Northwest Depleted Uranium Enrichment Program." Aggregate debt service for Project 1 is estimated by Energy Northwest to be about $1.9 billion for the remaining period that Project 1 debt is scheduled to be outstanding (Energy Northwest Fiscal Years 2012-2017). Aggregate debt service for Project 3 is estimated by Energy Northwest to be about $1.8 billion for the remaining period that Project 3 debt is scheduled to be outstanding (Energy Northwest Fiscal Years 2012-2018). In addition, Energy Northwest also has annual operating and maintenance expenses for the Energy Northwest Net Billed Projects, virtually all of which expenses are for Columbia Generating Station. By way of example, Energy Northwest estimates that Columbia Generating Station will have an operating expense of approximately $261.3 million in Energy Northwest Fiscal Year 2012.

Order in Which Bonneville's Costs Are Met

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at Federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayment of appropriated amounts to the Corps and Reclamation for costs that are allocated to power generation at Federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its Fiscal Year 2011 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $830 million in Fiscal Year 2011, approximately $70 million was for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. Such United States Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. Bonneville plans to make similar advance amortization payments to the United States Treasury at least through Fiscal Year 2012.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all non-United States Treasury cash payment obligations of Bonneville, including cash payments for lease rental payments under the Lease 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 lease rental payments under the Lease 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 2012 BONDS."

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

Bonneville is authorized to enter into new agreements to provide for additional net billing of its customers' bills. Nevertheless, because Bonneville is now able to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount in the Bonneville Fund and available borrowing authority, the primary reason for using net billing no longer exists. Bonneville has no present plans to enter into new agreements with Participants requiring net billing to fund resource acquisitions or other capital program investments, although Bonneville is exploring the use of billing credits related to prepayments by Participants of future power bills. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Consideration of a Prepaid Power Program." For a description of the Net Billing Agreements, net billing, and Participants, see "—Energy Northwest Net Billing Agreements."

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

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

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

Direct Pay Agreements

In Fiscal Year 2006, Bonneville and Energy Northwest entered into certain Direct Pay Agreements. Under these agreements, Bonneville has agreed by contract to pay directly to Energy Northwest the costs of Columbia Generating Station, Project 1, and Project 3 as billed to Bonneville by Energy Northwest. Under these agreements, Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both Federal and non-Federal.

By reducing the amount of net billing credits, Bonneville receives and will receive more revenues in cash from Participants during times of the year when Bonneville would otherwise carry its lowest annual cash balance, typically after Bonneville makes its end of fiscal year payment to the United States Treasury. As a consequence of re-shaping its annual cash flow patterns under the Direct Pay Agreements, Bonneville believes that those beneficial power rate effects will persist so long as the Direct Pay Agreements remain in effect and are complied with.

The Direct Pay Agreements did not and do not result in the amendment or termination of the Net Billing Agreements or any other agreements of Bonneville and Energy Northwest. The Participants' obligations to pay for power purchased from Bonneville did not and do not change as a result of the Direct Pay Agreements. The effect of the agreements is that the Participants no longer pay such amounts to Energy Northwest (with resulting net billing credits from Bonneville) for the period that the Direct Pay Agreements remain in effect. Rather, the Participants pay their billings by Bonneville for power and transmission services to Bonneville. The Direct Pay Agreements provide that, in the event that Bonneville were to fail to make required payments under the Direct Pay Agreements, Energy Northwest would re-initiate net billing as required under the Net Billing Agreements.

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. Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both Federal and non-Federal. The EWEB direct pay agreement did not and does not result in the amendment or termination of the EWEB Net Billing Agreement. There is no debt outstanding related to the Trojan Nuclear Project and EWEB's 30 percent share of the costs of the Trojan Nuclear Project is approximately $1.5 million per year.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for the Corps, Reclamation, and the Fish and Wildlife Service in Fiscal Year 2011 were $170 million, $88 million, and $22 million, respectively.

Bonneville believes that, in contrast to prior practice, the direct funding approach increases Bonneville's influence on the Corps' and the Department of Interior's Federal System operations and maintenance activities, expenses, and budgets because, in general, Bonneville's approval is necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-Federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct funding would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct funding could be made to the exclusion of non-Federal payments that would otherwise have been paid under historical practice. A result of any direct funding obligation by Bonneville is that there has been and will be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, Bonneville expects to have roughly $692 million to $827 million in scheduled payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses, through Fiscal Year 2013. Bonneville expects that it will renew and extend the direct funding agreements with the Corps and the Department of Interior prior to the expiration dates of the respective agreements.

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

Position Management and Derivative Instrument Activities and Policies

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

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

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

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2009 through 2011 are set forth in the following "Federal System Statement of Revenues and Expenses (unaudited)" table. Such data have been derived from the annual audited financial statements of the Federal System and differ therefrom in some respects in the categorization of certain costs. The audited Financial Statements of the Federal System (prepared in accordance with generally accepted accounting principles ("GAAP") and provided as Appendix B-1 to the Official Statement) include accounts of Bonneville as well as those of the generating facilities that are located in the Region and owned by the Corps and Reclamation and for which Bonneville is the power marketing agency and operation and maintenance costs of the Fish and Wildlife Service.

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

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

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

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

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for bookouts has no effect on net revenues, cash flows, or margins.

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

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife payment credits (also referred to as "4(h)10(C) credits") that reduce Bonneville's United States Treasury repayment obligation. Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The amount of such credits was about $99.5 million, $123.1 million, and $85.1 million in Fiscal Years 2009, 2010, and 2011, respectively. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." In addition, under Accounting Standards Codification 815 ("ASC 815"), Derivatives and Hedging, Bonneville reported an unrealized mark-to-market loss of $34.7 million, an unrealized gain of $14.8 million, and no gain or loss in Fiscal Years 2009, 2010, and 2011, respectively. ASC 815 requires (i) that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and (ii) that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. It is Bonneville's policy to document and apply as appropriate the normal purchases and normal sales exception under ASC 815. Purchases and sales of forward electricity and option contracts that require physical delivery which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under ASC 815. These transactions are not required to be recorded at fair value in the financial statements. Bonneville does not apply hedge accounting. The gain or loss of zero in Fiscal Year 2011 compared to $14.8 million unrealized gain in Fiscal Year 2010, resulted from Bonneville applying Accounting Standards Codification 980, Regulated Operations, in Fiscal Year 2010 to its commodity contract derivative instruments that are recorded at fair value and do not meet the normal purchases and normal sales exception. As a result, unrealized gains or losses associated with Bonneville's derivative instruments are recorded on the Combined Balance Sheets under regulatory assets and regulatory liabilities rather than in the Combined Statements of Revenues and Expenses.

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

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

(8) The Non-Federal entities O&M – net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which Bonneville has agreed to purchase under net billing agreements, which are capitalized contracts that cover the costs of Energy Northwest's terminated Project 1, terminated Project 3, and operating Columbia Generating Station, and EWEB's 30 percent ownership share of the terminated Trojan Nuclear Project.

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

(10) Non-Federal Projects Debt Service includes payments by Bonneville for all or a part of the generating capability of, and the related debt service, including interest, for Energy Northwest's nuclear power generating projects described in footnote (8) above.

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

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

(13) Lease Financing Program is included in Net Interest Expense as reported in the audited financial statements of the Federal System. Amounts shown are calculated on an accrual basis.

Management Discussion of Operating Results

Fiscal Year 2011

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

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

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

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

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

Fiscal Year 2010

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

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

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

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

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

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

Fiscal Year 2009

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

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

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

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

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

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

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

Statement of Non-Federal Project Debt Service Coverage

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

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

Fiscal Years ending September 30,	**2011**	**2010**	**2009**
Total Operating Revenues	$3,284,774	$3,055,131	$2,870,284
Less: Operating Expense[1]	1,640,415	1,707,561	1,640,904
Net Funds Available for Non-Federal Project Debt Service	1,644,359	1,347,570	1,229,380
Less:			
Non-Federal Project Debt Service[2]	624,972	600,360	501,367
Lease Financing Program[3]	23,872	20,718	17,369
Revenue Available for Treasury	995,515	726,492	710,644
Amount Allocated for Payment to Treasury[8]:			
Corps and Reclamation O&M[4]	280,349	271,502	255,059
Net Interest Expense[5]	272,359	243,342	218,429
Lease Financing Program[3]	(23,872)	(20,718)	(17,369)
Capitalization Adjustment[6]	64,905	64,905	64,905
Allowance for Funds Used During Construction[5] [7]	25,022	16,109	12,093
Amortization of Principal	409,528	459,829	432,019
Total Amount Allocated for Payment to Treasury[8]	1,028,291	1,034,969	965,136
Revenues Available for Other Purposes[9]	(32,776)	(308,477)	(254,492)
Non-Federal Project Debt Service Coverage Ratio[10]	2.5	2.2	2.4
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[11]	1.4	1.3	1.3

____

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

(2) Includes debt service for generating resources acquired by Bonneville under Net Billing Agreements or other capitalized contracts, including the Agreement. Non-net billed debt service amounted $39.5 million, $53.4 million, and $16.8 million for Fiscal Years 2009, 2010, and 2011 respectively.

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

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

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

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

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

(8) In contrast to the "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2009, 2010, and 2011 were $845 million, $864 million, and $830 million respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation, and Fish and Wildlife Service as portrayed under "Corps and Reclamation O&M." See "—Direct Funding of Federal System Operations and Maintenance Expense."

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

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

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

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

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

Management Discussion of Unaudited Results for the Six Months Ended March 31, 2012

For the six months in the fiscal year-to-date ended March 31, 2012 ("Fiscal Year 2012 Second Quarter"), net revenues decreased $79 million, or about five percent, when compared to the same period of the prior fiscal year. Power Services sales decreased $100 million, or eight percent, primarily due to new Tiered Rates that went into effect October 1, 2011 and a decrease in secondary megawatt-hour sales resulting from lower start-of-year reservoir levels and a persistently lower market price environment compared to the same period of the prior fiscal year. Tiered Rates significantly flatten the PF revenues across the year compared to the prior rate design, resulting in lower average rates in the six months ended March 31, 2012. The decreased PF revenues were partially offset by the $7 million decrease in the Residential Exchange Program Refund Amount compared to the same period of the prior fiscal year. Transmission Services sales increased $21 million, or six percent, primarily due to increased sales of Point-to-Point service and an increase in the associated ancillary services. For the six months ended March 31, 2012, 4(h)(10)(C) credits decreased $9 million, or 18 percent, primarily due to lower Fish and Wildlife capital program costs and lower volume and prices of purchased power for fish mitigation compared to same period of the prior fiscal year.

Operations and maintenance expense increased $30 million, or four percent, for the six months ended March 31, 2012, when compared to the same period of the prior fiscal year, primarily due to additional costs for fish and wildlife of $26 million, direct funding for Federal hydro projects of $15 million, Residential Exchange Program of $15 million, Transmission Services programs of $14 million, and other agency costs of $7 million. Fish and wildlife increases were driven by changes in the Council Program and additional work related to implementation of the 2010 Supplemental Columbia River System Biological Opinion and Columbia Basin Fish Accords. These increases were partially offset by a decrease in maintenance expense of $47 million at Columbia Generating Station since biennial refueling and maintenance took place in Fiscal Year 2011. Purchased power expense decreased $13 million, or 11 percent, for the six months ended March 31, 2012, when compared to the same period of the prior fiscal year. The decrease was primarily due to higher year-over-year hydro generation and a persistently lower market price environment, which reduced the amount and cost of power purchases required to meet Bonneville's load obligations. The decrease in purchased power expense is largely offset by an increase of $32 million from costs related to a new hydro storage agreement with Canada.

Nonfederal projects expense increased $25 million, or nine percent, for the six months ended March 31, 2012, when compared to the same period of the prior fiscal year, primarily due to increased scheduled debt payments for Project 1 partially offset by reduced scheduled debt payments for Columbia Generating Station and Project 3.

Net interest expense decreased $24 million, or 19 percent, for the six months ended March 31, 2012, when compared to the same period a year earlier. Interest expense decreased $6 million, or three percent, primarily due to higher beginning debt balances. Allowance for funds used during construction increased $8 million, or 45 percent, reflecting increased construction work in progress balances related to capital investments for generation and transmission assets. Interest income increased $10 million, or 57 percent, as a result of a one-time $16 million accrual for interest income related to outstanding accounts receivable, which was partially offset by lower cash balances and interest rates. In addition, for the fourth consecutive fiscal year, $100 million was transferred from the Bonneville Fund to market-based special securities which are currently earning lower yields.

For further information regarding Fiscal Year 2012 Second Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2012." For information regarding Bonneville's Fiscal Year 2012 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2012 Expectations."

BONNEVILLE LITIGATION

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

ESA Litigation

Columbia River

In a lawsuit filed May 4, 2001, in the Oregon Federal District Court, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Federal Columbia River Power System Biological Opinion and incidental take statement were arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NOAA Fisheries to reinitiate consultation with the Action Agencies responsible for operation of the Federal System hydroelectric projects and to prepare a new biological opinion.

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

On November 30, 2004, NOAA Fisheries finalized a subsequent biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies identified by the Oregon Federal District Court. Plaintiffs filed a complaint against NOAA Fisheries and subsequently filed another complaint against the Corps and Reclamation with the Oregon Federal District Court alleging that the 2004 Biological Opinion and the Corps' and Reclamation's decisions to operate consistent with the Biological Opinion violated certain provisions of the ESA and Administrative Procedures Act. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The court issued an order remanding the matter to the Federal agencies to correct identified deficiencies. Additionally, in the court's remand order, the Federal agencies were ordered to undertake collaboration with the sovereign parties to the litigation (states and tribes) to address key issues in a new biological opinion. The Federal Government and the State of Idaho appealed the order to the Ninth Circuit Court, which ultimately denied the appeals and upheld the order.

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

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

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

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

For 2006 river operations, the Federal agencies proposed (and the court approved) a spill program that was similar although not identical to the spill program the court had ordered in the summer of 2005. Bonneville estimated that the 2006 spill order, which included spring as well as summer spill, resulted in somewhat greater hydroelectric generation than would have occurred under the 2005 summer spill program. For hydro-operations in each of 2007-2012, the Federal agencies proposed a spill program similar to the 2006 spill program and obtained court approvals. For 2013 river operations, the Federal agencies expect to propose spill programs for spring and summer as provided in the 2010 Supplemental Columbia River System Biological Opinion, which are similar to the 2006 spill program.

DSI Service Litigation

On June 30, 2005, Bonneville issued a Record of Decision entitled "Bonneville Power Administration's Service to the Direct Service Industrial Customers for Fiscal Years 2007-2011" ("DSI ROD"). The DSI ROD established a policy that defined the service benefits that Bonneville would provide to the DSIs during Fiscal Years 2007 through 2011, among other things. The DSI ROD included the possibility that Bonneville would provide DSIs with service benefits in the form of either electric power at rates favorable to DSIs or monetized power benefits.

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

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

Townsend, a small non-aluminum industry DSI. Finally, in November 2006, the Industrial Customers of Northwest Utilities ("ICNU") filed a petition that likewise challenged the Port Townsend power sales contract.

In December 2008, the Ninth Circuit Court announced a decision (referred to as "PNGC I") affirming that Bonneville has the statutory authority, but not the obligation, to sell power to the DSIs after Fiscal Year 2001. However, the court determined that if Bonneville elects to sell industrial firm power to DSIs, Bonneville must first offer such power at the IP Rate. Only after the DSIs have refused to purchase power at the IP Rate may Bonneville offer them power under Bonneville's FPS rate schedule. The court also agreed with Bonneville that it has the authority to monetize its DSI contracts in some circumstances, so long as doing so is otherwise consistent with Bonneville's statutory obligations.

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

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

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

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

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

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

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

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

Tiered Rates Methodology Record of Decision

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

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

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

2010 and 2012 Power Rates Challenges

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

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

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

Residential Exchange Program Litigation

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

Beginning in 2000, a number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the 2000 Residential Exchange Program Settlement Agreements, among other things. Among those participating in the litigation were a group of DSIs, all six Regional IOUs, and a number of Preference Customers and Preference Customer groups. The litigation challenging the 2000 Residential Exchange Program Settlement Agreements is referred to as the "PGE Proceeding." Certain customers also challenged, in another proceeding referred to as the "Golden Northwest Proceeding," Bonneville's power rates in Fiscal Years 2002 through 2006 associated with the 2000 Residential Exchange Program Settlement.

On May 3, 2007, the Ninth Circuit Court issued an opinion in the PGE Proceeding holding that Bonneville failed to properly implement the Residential Exchange Program provisions of the Northwest Power Act when it entered into the 2000 Residential Exchange Program Settlement Agreements, and that such agreements are "inconsistent with the Northwest Power Act." The court in the Golden Northwest Proceeding held, among other things, that consistent with its holding in the PGE Proceeding, Bonneville improperly allocated to Preference Customers' rates the costs of providing Residential Exchange Program benefits to the Regional IOUs under the 2000 Residential Exchange Program Settlement Agreements. The Regional IOUs filed petitions for rehearing of the ruling in the PGE Proceeding. The motions were denied.

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

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

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

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

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

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

Southern California Edison v. Bonneville Power Administration

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

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

> **Conversion from Sale to Exchange Mode ("Conversion Claim")**. SCE filed an action in the Court of Federal Claims on December 26, 2002, based on its assertion that the claim should be "deemed denied" by Bonneville. SCE sought damages in the amount of approximately $186,000,000.
>
> **Termination for Default ("Termination Claim")**. In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. SCE filed a complaint in November 2004 seeking $22,000,000 in termination for convenience damages.

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

Rates Litigation Generally

Bonneville's rates are frequently the subject of litigation. Most of the litigation involves claims that Bonneville's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record or are arbitrary and capricious. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates."

It is the opinion of Bonneville's General Counsel that if any rate were to be rejected, the sole remedy accorded would be a remand to Bonneville to establish a new rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville is unable to predict, however, what new rate it would establish if a rate were rejected. If Bonneville were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid. However, Bonneville is required by law to set rates to meet all of its costs. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Lease-Purchase Program Property Taxes

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

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

Miscellaneous Litigation

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

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APPENDIX B-1

FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS
FOR THE YEARS ENDED SEPTEMBER 30, 2011, 2010 AND 2009

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Report of Independent Auditors

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

In our opinion, the accompanying combined balance sheets and the related combined statements of revenues and expenses, of changes in capitalization and long-term liabilities and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2011, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the FCRPS' management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

October 27, 2011

PricewaterhouseCoopers LLP, 1300 SW Fifth Ave, Suite 3100, Portland, OR 97201
T: (971) 544 4000, F: (971) 544 4100, www.pwc.com/

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

(Thousands of Dollars)

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

The accompanying notes are an integral part of these statements.

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

(Thousands of Dollars)

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

The accompanying notes are an integral part of these statements.

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

(Thousands of Dollars)

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

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Combined Statements of Changes in Capitalization and Long-Term Liabilities
Including Current Portions

(Thousands of Dollars)

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

The accompanying notes are an integral part of these statements.

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

(Thousands of Dollars)

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

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination and consolidation of entities

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

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

FCRPS accounts are maintained in accordance with generally accepted accounting principles of the United States of America and the Uniform System of Accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect specific legislation and directives issued by U.S. government agencies. BPA is a separate and distinct entity within the U.S. Department of Energy; Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior; and the Corps is part of the U.S. Department of Defense. U.S. government properties and income are tax exempt.

Use of estimates

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

Rates and regulatory authority

BPA establishes separate power and transmission rates in accordance with several statutory directives. Rates proposed by BPA are subject to an extensive formal hearing process, after which they are proposed by BPA and reviewed by FERC. FERC’s review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. 839, and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. Statutory standards include a requirement that these rates be sufficient to ensure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA’s other costs. After final FERC approval, BPA’s rates are subject to review by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court). Action seeking such review must be filed within 90 days of the final FERC decision. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA.

In accordance with authoritative guidance for Regulated Operations, certain costs or credits may be included in rates for recovery or refund over a future period and are recorded as regulatory assets or liabilities. (See Note 3, Effects of Regulation.) Regulatory assets or liabilities are amortized over the periods they are included in rates. Costs are recovered through rates during the periods when the costs are scheduled to be repaid. Amortization is computed using either the straight-line method or is based upon specific amounts included in rates each year. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return.

Utility plant

Utility plant is stated at original cost and includes generation and transmission assets. Generation assets were $7.96 billion and $7.76 billion, and transmission assets were $6.78 billion and $6.60 billion at Sept. 30, 2011, and 2010, respectively. The costs of substantial additions, major replacements and substantial betterments are capitalized. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. Maintenance, repairs and replacements of items determined to be less than major units of property are charged to maintenance and operating expense as incurred. When BPA retires utility plant, it charges the original cost and any net proceeds from the disposition to accumulated depreciation.

Depreciation

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated service lives of the various classes of property, which average 75 years. For transmission plant, depreciation of original cost and estimated net cost of removal is computed primarily on the straight-line group life method based on estimated service lives of the various classes of property, which average 40 years. The net cost of removal is included in depreciation; however, in the event there is negative salvage, a reclassification of the negative salvage reserve not associated with asset retirement obligations is made from accumulated depreciation to a regulatory liability.

Allowance for funds used during construction

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

FCRPS capitalizes AFUDC at one rate for Corps and Reclamation construction funded by congressional appropriations and at another rate for construction funded substantially by BPA and the NIFCs. The rates for appropriated funds are provided each year to BPA by the U.S. Treasury, whereas the BPA rate is determined based on the weighted-average cost of borrowing for BPA and the NIFCs. The respective rates were approximately 0.3 percent and 4.4 percent in fiscal year 2011, 0.4 percent and 4.8 percent in fiscal year 2010, and 2.0 percent and 5.2 percent in fiscal year 2009.

Nonfederal generation

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

Cash and cash equivalents

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

Concentrations of credit risks

General credit risk

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

BPA's accounts receivable are spread across a diverse group of consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators and others that are located throughout the western United States and Canada. The accounts receivable exposure results from BPA providing a wide variety of power products and transmission services. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. During fiscal years 2011, 2010 and 2009, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. In order to further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, cash in the form of prepayment and deposit or escrow from some counterparties. BPA closely monitors counterparties for changes in financial condition and regularly updates credit reviews.

Allowance for doubtful accounts

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

The largest risk relates to the California power markets that were in turmoil during 2000 to 2001 when they experienced historically high power prices and volatility, along with continued uncertainty related to deregulation. The California Independent System Operator and California Power Exchange were customers with whom BPA had contracts for power and transmission delivery during that period, and they have not fully paid BPA for their purchases. (See Note 13, Commitments and Contingencies.) BPA has recorded an allowance for these accounts, which in management's best estimate is sufficient to cover potential exposure. Net exposure after this allowance is not significant. BPA has continued to pursue collection of amounts due.

Derivative instruments

BPA follows the Derivatives and Hedging accounting guidance that requires every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and also requires that a change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is BPA's policy to document and apply as appropriate the normal purchases and normal sales exception under the Derivatives and Hedging accounting guidance. Forward electricity contracts are generally considered normal purchases and normal sales if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the definition of capacity described in the Derivatives and Hedging accounting guidance. These transactions are not required to be recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle.

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

Fair value

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

Revenues and net revenues

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

Interest income

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

U.S. Treasury credits for fish

The Northwest Power Act obligates the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and nonpower purposes on a reimbursement basis. The Northwest Power Act also specifies that consumers of electric power, through their rates for power services, "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Northwest Power Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects. Power related costs are recovered in BPA's rates. Nonpower related costs are recovered as a reduction to BPA's cash payment to the U.S. Treasury.

Residential Exchange Program

In order to provide qualifying regional utilities, primarily IOUs, access to benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of the Northwest Power Act. Whenever a Pacific Northwest electric utility offers to sell power to BPA at the utility's average system cost of resources, BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA's priority firm exchange rate to the utility for resale to that utility's residential and small farm consumers. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing rates. The cost of this program is collected through rates with program costs recognized when incurred net of the purchase and sale of power under the REP.

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

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

RECENT ACCOUNTING PRONOUNCEMENTS

Receivables

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

Fair value measurements and disclosures

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

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

Variable interest entities

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

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

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

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

SUBSEQUENT EVENTS

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

2. Investments in U.S. Treasury Securities

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

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

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

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

3. Effects of Regulation

REGULATORY ASSETS

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

Regulatory assets include the following items:

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

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

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

"Columbia River Fish Mitigation" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. These costs are recovered through rates and amortized as scheduled over 75 years.

"Conservation measures" consist of the costs of capitalized conservation measures and are amortized over periods from five to 20 years.

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

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

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

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

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

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

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

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

"Sponsored conservation" relates to the nonfederal debt for Conservation and Renewable Energy System (CARES) and City of Tacoma Conservation bonds. These were issued to finance conservation programs sponsored by BPA. The assets are amortized as the principal on the outstanding debt is repaid.

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

REGULATORY LIABILITIES

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

Regulatory liabilities include the following items:

"Capitalization adjustment" is the difference between appropriated debt before and after refinancing per the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (Refinancing Act), 16 U.S.C. 838(l). The adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act. Amortization of the capitalization adjustment was $64.9 million for fiscal years 2011, 2010 and 2009, respectively. (See Note 6, Federal Appropriations.)

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

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

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

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

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

4. Asset Retirement Obligations

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

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

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

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

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

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

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

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

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

5. Deferred Charges and Other

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

Deferred charges and other include the following items:

"Special purpose corporations' trust funds" are amounts held in separate trust accounts for the construction of transmission assets, debt service payments during the construction period and a fund mainly for future principal and interest debt service payments. (See Note 8, Nonfederal Financing.)

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

The Commercial Spectrum Enhancement Act created the "Spectrum Relocation fund" to reimburse the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to federal agencies. Amounts received from the U.S. Treasury in connection with the Act are held in the BPA fund and are restricted for use in constructing replacement assets.

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

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

6. Federal Appropriations

Appropriations consist primarily of the power portion of Corps and Reclamation capital investments funded through congressional appropriations and the remaining unpaid capital investments in the BPA transmission system, which were made prior to implementation of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. 838(j).

The Refinancing Act required that the outstanding balance of the FCRPS federal appropriations be reset and assigned market rates of interest prevailing as of Oct. 1, 1996. This resulted in a determination that the principal amount of appropriations should be equal to the present value of the principal and interest that would have been paid to the U.S. Treasury in the absence of the Refinancing Act, plus $100 million. Appropriations in the amount of $6.69 billion were subsequently refinanced for $4.10 billion. This adjustment was recorded as a capitalization adjustment in regulatory liabilities and is being amortized over the remaining period of repayment. (See Note 3, Effects of Regulation.)

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

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

MATURING FEDERAL APPROPRIATIONS

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

7. Borrowings from U.S. Treasury

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

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

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

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

MATURING BORROWINGS FROM U.S. TREASURY

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

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

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

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

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

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

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

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

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

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

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

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

Nonfederal debt includes both operating and nonoperating projects. BPA recognizes expenses for these projects based upon total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $328.1 million, $262.6 million and $291.0 million in fiscal years 2011, 2010 and 2009, respectively, which is included in Operations and maintenance in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $625.0 million, $600.4 million and $501.4 million for fiscal years 2011, 2010 and 2009, respectively, is reflected as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars

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

1989 Letter Agreement

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

VARIABLE INTEREST ENTITIES

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

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

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

9. Residential Exchange Program

BACKGROUND

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

In 2000, BPA signed Residential Exchange Program Settlement Agreements ("REP settlements" or "settlement agreements") with the region's six IOUs under which BPA provided monetary and power benefits as a settlement of Residential Exchange disputes for the period July 1, 2001, through Sept. 30, 2011. BPA later signed additional agreements and amendments with IOU customers related to the settlement agreements. One such agreement provided for the elimination or deferral of certain IOU benefit payments, while later agreements and amendments provided for minimum and maximum amounts for the IOU monetary benefits for fiscal years 2007 through 2011, provided that BPA would have no obligation to provide power to the IOUs in this period. When future amounts were committed through these agreements, BPA recorded a REP settlement liability for the minimum committed amounts and a regulatory asset for amounts recoverable in future rates.

LOOKBACK AMOUNT

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

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

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

IOU EXCHANGE BENEFITS

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

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

2009 DEEMER ADJUSTMENT

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

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

2012 RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT

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

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

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

10. Deferred Credits and Other

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

Deferred credits and other include the following items:

"Generation interconnection agreements" are generators' advances held as security for requested new network upgrades and interconnection. These advances accrue interest and will be returned as credits against future transmission service on the new or upgraded lines.

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

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

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

"Fiber optic leasing fees" reflect unearned revenue related to the leasing of the fiber optic cable. Revenue is being recognized over the lease terms extending out to 2020.

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

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

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

11. Risk Management and Derivative Instruments

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

RISK MANAGEMENT

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

COMMODITY PRICE RISK AND VOLUMETRIC RISK

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

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

CREDIT RISK

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

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

INTEREST RATE RISK

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

DERIVATIVE INSTRUMENTS

BPA follows the Derivatives and Hedging accounting guidance that requires every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and also requires that a change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

COMMODITY CONTRACTS

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

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

Prior to this adoption, BPA recorded the changes in fair value under Derivative instruments in the current period in the Combined Statements of Revenues and Expenses. When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. (See Note 12, Fair Value Measurements.)

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

INTEREST RATE SWAP TRANSACTIONS

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

DERIVATIVE ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

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

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

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

AMOUNT OF GAIN (LOSS) RECOGNIZED

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

12. Fair Value Measurements

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

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

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

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

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

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

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

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

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2011 — thousands of dollars

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

As of Sept. 30, 2010 — thousands of dollars

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

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

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

COMMODITY CONTRACTS

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

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

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

13. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. BPA makes expenditures and incurs other costs for fish and wildlife projects that are consistent with the Northwest Power Act and that are consistent with the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish species are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions (BiOp) prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA. BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp is not fixed or determinable. However, the current estimate of long-term fish and wildlife agreements with a contractual commitment which BPA has entered into is $1.03 billion. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

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

As directed by legislation, BPA is required to make cash distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects that have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation. In establishing power rates, particular statutory provisions guide the assumptions that BPA makes as to the amount and timing of such distributions. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues (expenses) when paid. Future irrigation assistance payments are scheduled to total $666.1 million over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. BPA is required by the Grand Coulee Dam - Third Powerplant Act to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects to the extent the costs have been determined to be beyond the irrigators' ability to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period. Irrigation assistance excludes $40.3 million for Teton Dam which failed prior to completion and for which BPA has no obligation to recover these costs.

FIRM PURCHASE POWER COMMITMENTS

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

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

NUCLEAR INSURANCE

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

Under each insurance policy, BPA could be subject to a retrospective premium assessment in the event that a member insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Liability Insurance policy is $9.1 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $18.7 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $5.0 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $375.0 million, BPA could be subject to a retrospective assessment of up to $111.9 million limited to an annual maximum of $17.5 million. Assessments would be included in BPA's costs and recovered through rates.

ENVIRONMENTAL MATTERS

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

LITIGATION

Southern California Edison

Southern California Edison (SCE) filed two separate actions pending in the U.S. Court of Federal Claims against BPA related to a power sales and exchange agreement (Sale and Exchange Agreement) between BPA and SCE. The actions challenged: 1) BPA's decision to convert the contract from a sale of power to an exchange of power as provided for under the terms of the contract (Conversion Claim); and 2) BPA's termination of the Sales and Exchange Agreement due to SCE's nonperformance (Termination Claim).

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

California parties' refund claims

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

Rates

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

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

Other

The FCRPS may be affected by various other legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. BPA is unable to predict whether the FCRPS will avoid adverse outcomes in these legal proceedings; however, BPA believes that disposition of pending matters will not have a materially adverse effect on the FCRPS' financial position or results of operations for fiscal year 2011.

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

APPENDIX B-2

FEDERAL SYSTEM UNAUDITED REPORT
FOR THE SIX MONTHS ENDED MARCH 31, 2012

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Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Thousands of dollars)

	As of March 31, 2012	As of September 30, 2011
Assets		
Utility plant		
Completed plant	$ 14,765,325	$ 14,741,720
Accumulated depreciation	(5,511,988)	(5,436,160)
	9,253,337	9,305,560
Construction work in progress	1,631,504	1,396,097
Net utility plant	10,884,841	10,701,657
Nonfederal generation	2,594,846	2,604,078
Current assets		
Cash and cash equivalents	1,161,884	892,125
Short-term investments in U.S. Treasury securities	338,120	253,348
Accounts receivable, net of allowance	127,124	119,596
Accrued unbilled revenues	310,340	207,089
Materials and supplies, at average cost	101,682	93,924
Prepaid expenses	33,717	29,430
Total current assets	2,072,867	1,595,512
Investments and other assets		
Regulatory assets	7,575,007	7,812,358
Investments in U.S. Treasury securities	24,648	39,129
Nonfederal nuclear decommissioning trusts	224,869	198,809
Deferred charges and other	284,337	223,736
Total investments and other assets	8,108,861	8,274,032
Total assets	$ 23,661,415	$ 23,175,279
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	$ 2,621,145	$ 2,510,373
Federal appropriations	4,318,323	4,324,881
Borrowings from U.S. Treasury	2,928,440	2,678,440
Nonfederal debt	5,961,285	5,843,046
Total capitalization and long-term liabilities	15,829,193	15,356,740
Commitments and contingencies (See Note 13 to annual financial statements)		
Current liabilities		
Federal appropriations	24,622	24,622
Borrowings from U.S. Treasury	325,000	265,000
Nonfederal debt	430,100	429,545
Accounts payable and other	509,208	523,459
Total current liabilities	1,288,930	1,242,626
Other liabilities		
Regulatory liabilities	2,444,892	2,456,343
IOU exchange benefits	3,113,122	3,161,251
Asset retirement obligations	180,277	176,212
Deferred credits and other	805,001	782,107
Total other liabilities	6,543,292	6,575,913
Total capitalization and liabilities	$ 23,661,415	$ 23,175,279

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Fiscal Year-to-Date Ended March 31, 2012	Fiscal Year-to-Date Ended March 31, 2011
Operating revenues				
Sales	$ 837,249	$ 890,377	$ 1,621,465	$ 1,700,687
U.S. Treasury credits for fish	21,382	25,130	41,724	50,896
Miscellaneous revenues	20,744	16,182	34,376	31,128
Total operating revenues	879,375	931,689	1,697,565	1,782,711
Operating expenses				
Operations and maintenance	447,154	428,308	863,868	834,202
Purchased power	61,567	32,353	106,182	119,238
Nonfederal projects	158,707	147,745	320,658	295,492
Depreciation and amortization	94,532	99,156	192,363	195,214
Total operating expenses	761,960	707,562	1,483,071	1,444,146
Net operating revenues	117,415	224,127	214,494	338,565
Interest expense and (income)				
Interest expense	72,088	82,532	158,351	163,999
Allowance for funds used during construction	(13,496)	(9,357)	(26,818)	(18,557)
Interest income	(22,722)	(10,234)	(27,811)	(17,687)
Net interest expense	35,870	62,941	103,722	127,755
Net revenues (expenses)	$ 81,545	$ 161,186	$ 110,772	$ 210,810

APPENDIX C

FORM OF OPINION OF ORRICK, HERRINGTON & SUTCLIFFE LLP

July 24, 2012

Port of Morrow
2 Marine Drive
Boardman, OR 97818

Re: Port of Morrow
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1)
Series 2012

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 $84,740,000 aggregate principal amount of the Issuer's Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1), Series 2012 (the "Series 2012 Bonds"), issued pursuant to an Indenture of Trust, dated as of July 1, 2012 (the "Indenture"), between the Issuer and U.S. Bank National Association, as trustee (the "Trustee"). The Series 2012 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 Agreement, dated as of July 1, 2012 (the "Lease 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 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 March 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 2012 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 2012 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 2012 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 Agreement.

We call attention to the fact that the rights and obligations under the Series 2012 Bonds, the Indenture and the Lease 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 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 Agreement to the effect that the Lease 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 Agreement to ascertain the intent of the parties in using the language employed in the Lease Agreement, regardless of whether or not the meaning of the language used in the Lease Agreement is plain and unambiguous on its face, and may determine that additional or supplemental terms can be incorporated into the Lease Agreement. Furthermore, under Washington law, the parties to the Lease Agreement can modify the Lease Agreement by their conduct, and a party seeking to enforce the Lease Agreement may be required to perform its obligations under the Lease 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 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 2012 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 2012 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 Agreement constitutes the valid and binding agreement of the Issuer.

4. Interest on the Series 2012 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 2012 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

$84,740,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1)
Series 2012

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. 1) Series 2012 (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 in the tables titled "Federal System Statement of Revenues and Expenses" and "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" both under the heading "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS."

"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 July 18, 2012.

"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, 2012:

i. the BPA Annual Information for the FCRPS Fiscal Year; and

ii. annual financial statements of the FCRPS for the FCRPS Fiscal Year, prepared in accordance with generally accepted accounting principles; and

iii. if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville 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. Material Events. 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 material 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 material 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 _____ day of __________, 2012.

Bonneville Power Administration

____

Authorized Official

PORT OF MORROW, OREGON • Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1), Series 2012 (Federally Taxable)

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