NEW ISSUE — BOOK-ENTRY ONLY **Ratings: See "RATINGS"**

In the opinion of Orrick, Herrington & Sutcliffe, LLP, Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings, a procedure and methodology, and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2013 Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 and Section 9(f) of the Pacific Northwest Power Planning and Conservation Act, Public Law 96-501. In the further opinion of Special Tax Counsel, interest on the 2013 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings when calculating corporate alternative minimum taxable income. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2013 Bonds. See "TAX MATTERS."

PUBLIC UTILITY DISTRICT NO. 1
OF LEWIS COUNTY, WASHINGTON
$87,995,000
Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013

Dated: Date of Delivery **Due: As shown on the inside cover page**

Public Utility District No. 1 of Lewis County, Washington (the "District") is issuing its Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 (the "2013 Bonds") as fully registered bonds under a book-entry only system, initially registered in the name of Cede & Co., as nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2013 Bonds. Individual purchases of beneficial interests in the 2013 Bonds will be made in the principal amount of $5,000 or any integral multiple thereof within a single maturity. Purchasers of beneficial interests in the 2013 Bonds (the "Beneficial Owners") will not receive certificates representing their interest in the 2013 Bonds. Principal of and interest on the 2013 Bonds are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Registrar").

Principal of the 2013 Bonds is payable as set forth on the inside cover page. Interest on the 2013 Bonds is payable on October 1, 2013, and semiannually thereafter on each April 1 and October 1 to maturity or earlier redemption, by the Registrar to DTC, which in turn is obligated to remit such principal and interest to its broker-dealer participants for subsequent disbursement to Beneficial Owners of the 2013 Bonds. See Appendix H– "BOOK-ENTRY ONLY SYSTEM."

The 2013 Bonds are subject to redemption prior to their stated maturities. See "DESCRIPTION OF THE 2013 BONDS – Redemption."

The 2013 Bonds are being issued to refund the Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 (the "2003 Bonds") maturing on and after October 1, 2014, issued for the purpose of refunding outstanding bonds of the Cowlitz Falls Hydroelectric Project (the "Project" or "Cowlitz Falls Project"), a hydroelectric facility located on the Cowlitz River in Lewis County, Washington, and to pay costs of issuing the 2013 Bonds. See "PURPOSE OF THE 2013 BONDS AND APPLICATION OF THE 2013 BOND PROCEEDS."

The United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

("Bonneville"), has entered into a Power Purchase Contract with the District and a Payment Agreement with the Trustee. Pursuant to the Power Purchase Contract, all of the output of the Project through June 30, 2032 has been sold to Bonneville and Bonneville is obligated to pay all Project Power Costs (as defined in the Power Purchase Contract), including debt service on the 2013 Bonds, whether or not the Project is terminated, operating or operable. Bonneville is further obligated pursuant to the Payment Agreement to pay debt service on the 2013 Bonds if it does not make such payments under the Power Purchase Contract. See Appendix D – "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT." Bonneville's payments under the Power Purchase Contract and the Payment Agreement may be made solely from the Bonneville Fund as described herein. **Such obligations 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 2013 Bonds are special limited obligations of the District payable from the revenues derived from the Cowlitz Falls Project, and are not obligations of the State of Washington or of any political subdivision thereof, other than the District. The 2013 Bonds do not constitute a general obligation of the District or a charge upon any general fund or upon any money or property of the District, including the District's Electric System, except the Cowlitz Falls Revenues, as described herein, and money in certain funds and accounts held under the Resolution.

MATURITY SCHEDULE — See Inside Cover Page

The 2013 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Pepper PLLC, Seattle, Washington, Bond Counsel to the District, and to certain other conditions. Certain tax matters will be passed upon by Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville. Certain legal matters will be passed upon for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters. It is expected that the 2013 Bonds will be available for delivery through the facilities of DTC on or about July 10, 2013.

Citigroup

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

Dated: June 13, 2013

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

PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY, WASHINGTON

$87,995,000

COWLITZ FALLS HYDROELECTRIC PROJECT REVENUE REFUNDING BONDS, SERIES 2013

Year	Amount	Interest Rate	Yield	CUSIP No.* 527839
October 1, 2014	$2,940,000	2.00%	0.27%	CY8
October 1, 2015	3,000,000	5.00	0.51	CZ5
October 1, 2016	3,150,000	5.00	0.87	DA9
October 1, 2017	3,310,000	5.00	1.20	DB7
October 1, 2018	3,475,000	5.00	1.55	DC5
October 1, 2019	3,650,000	5.00	1.87	DD3
October 1, 2020	3,830,000	5.00	2.12	DE1
October 1, 2021	4,020,000	5.00	2.44	DF8
October 1, 2022	4,220,000	5.00	2.68	DG6
October 1, 2023	4,435,000	5.00	2.85	DH4
October 1, 2024	4,655,000	5.25	3.01**	DJ0
October 1, 2025	4,900,000	5.25	3.19**	DK7
October 1, 2026	5,155,000	5.25	3.35**	DL5
October 1, 2027	5,430,000	5.25	3.44**	DM3
October 1, 2028	5,710,000	5.25	3.53**	DN1
October 1, 2029	6,010,000	5.25	3.62**	DP6
October 1, 2030	6,330,000	5.25	3.69**	DQ4
October 1, 2031	6,660,000	4.00	4.29***	DR2
April 1, 2032	7,115,000	5.25	3.81**	DS0

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

** Priced to the October 1, 2023 par call date.

*** Priced to maturity.

PUBLIC UTILITY DISTRICT NO. 1
OF LEWIS COUNTY, WASHINGTON
321 Northwest Pacific Avenue
Chehalis, Washington 98532
(360) 748-9261
www.lcpud.org

BOARD OF COMMISSIONERS

Ben M. Kostick	President
Charles R. TenPas	Vice President
Dean Dahlin	Secretary

MANAGEMENT

Robert D. Geddes	Manager
Richard L. Bauer	Treasurer/Chief Financial Officer
Bradley J. Ford	Auditor
Greg Hart	Superintendent

BOND AND DISCLOSURE COUNSEL

Foster Pepper PLLC
Seattle, Washington

BONNEVILLE POWER ADMINISTRATION

P.O. Box 3621
Portland, Oregon 97208
(503) 230-3000

William K. Drummond, Administrator and Chief Executive Officer
Elliot Mainzer, Deputy Administrator (Acting)
Anita J. Decker, Chief Operating Officer
Randy A. Roach, Executive Vice President and General Counsel
Claudia R. Andrews, Executive Vice President and Chief Financial Officer

SPECIAL COUNSEL AND SPECIAL TAX COUNSEL TO BONNEVILLE

Orrick, Herrington & Sutcliffe LLP

No dealer, broker, salesperson or other person has been authorized by the District or by the Underwriters to give any information or to make any representations in connection with the issuance and sale of the 2013 Bonds other than as contained in this Official Statement, and, if given or made, such other information or representations must not be relied upon as having been authorized by the District or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy by, nor shall there be any sale of the 2013 Bonds to, any person in any jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

The information set forth herein has been furnished by the District and Bonneville and includes information obtained from other sources which the District and Bonneville believe to be reliable; however the information and expressions of opinion contained herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the District or Bonneville since the date hereof.

Information on website addresses set forth in this Official Statement is not incorporated into this Official Statement and cannot be relied upon to be accurate as of the date of this Official Statement, nor can any such information be relied upon in making investment decisions regarding the 2013 Bonds.

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

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

The presentation of certain information, including tables of receipts from revenues, is intended to show recent historic information and is not intended to indicate future or continuing trends in the financial position or other affairs of the District or Bonneville. No representation is made that past experience, as it might be shown by such financial and other information, will necessarily continue to be repeated in the future.

The 2013 Bonds will not be registered under the Securities Act of 1933, as amended, in reliance upon an exception contained in such act.

This Official Statement is not to be construed as a contract or agreement between the District, Bonneville and purchasers or owners of any of the 2013 Bonds.

The initial public offering prices or yields set forth on the inside cover page hereof may be changed from time to time by the Underwriters. The Underwriters may offer and sell the 2013 Bonds to certain dealers, unit investment trusts or money market funds at prices lower than the public offering prices stated on the inside cover page hereof.

TABLE OF CONTENTS

	Page
INTRODUCTORY STATEMENT	1
The District	1
Bonneville Power Administration	1
PURPOSE OF THE 2013 BONDS AND APPLICATION OF THE 2013 BOND PROCEEDS	2
Purpose of the 2013 Bonds	2
Estimated Sources and Uses of Funds	3
Verification of Mathematical Calculations	3
SECURITY FOR THE 2013 BONDS	3
Pledge of Cowlitz Falls Revenues	3
Power Purchase Contract	4
Payment Agreement	4
Flow of Funds	4
Reserve Account	5
Additional Bonds	5
Covenants	6
THE BONNEVILLE FUND	6
DESCRIPTION OF THE 2013 BONDS	7
Description	7
Registrar	8
Redemption	8
Purchases for Cancellation	9
Transfer and Registration	9
Termination of Book-Entry Only System	9
DEBT SERVICE REQUIREMENTS	10
THE COWLITZ FALLS PROJECT	10
Description of the Cowlitz Falls Project	10
Cowlitz Falls Project Output	10
Cowlitz Falls Project Annual Costs	12
Transmission of Cowlitz Falls Project Output	12
Environmental Issues	13
THE DISTRICT	13
General	13
Management and Administration	14
Labor Relations	14
Utility Operations	14
Power Supply	15
Insurance	15
LITIGATION	15
LEGAL MATTERS	16
TAX MATTERS	16
RATINGS	18
UNDERWRITING	18
CONTINUING DISCLOSURE	19
INITIATIVE AND REFERENDUM	20
MISCELLANEOUS	20

Appendix A	—	BONNEVILLE POWER ADMINISTRATION
Appendix B-1	—	FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS FOR THE YEARS ENDED SEPTEMBER 30, 2012 AND 2011
Appendix B-2	—	FEDERAL SYSTEM UNAUDITED REPORT FOR SIX MONTHS ENDED MARCH 31, 2013
Appendix C	—	SUMMARY OF THE RESOLUTION
Appendix D	—	SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT
Appendix E	—	PROPOSED FORM OF OPINION OF BOND COUNSEL
Appendix F	—	PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE 2013 BONDS
Appendix G	—	SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENT
Appendix H	—	BOOK-ENTRY ONLY SYSTEM

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PUBLIC UTILITY DISTRICT NO. 1
OF LEWIS COUNTY, WASHINGTON

OFFICIAL STATEMENT

$87,995,000
COWLITZ FALLS HYDROELECTRIC PROJECT
REVENUE REFUNDING BONDS, SERIES 2013

INTRODUCTORY STATEMENT

The District

Public Utility District No. 1 of Lewis County, Washington (the "District") furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of its Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 (the "2013 Bonds"). This Introduction is not intended to provide all information material to a prospective purchaser of the 2013 Bonds and is qualified in all respects by the more detailed information set forth elsewhere in this Official Statement. Unless otherwise specifically defined, certain capitalized terms used in this Introduction have the meanings given to such terms elsewhere in this Official Statement. See Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution."

The District is issuing the 2013 Bonds pursuant to Title 54 and Chapter 39.53 of the Revised Code of Washington ("RCW") and Resolution No. 2245 of the District, adopted on June 19, 2003 (the "2003 Resolution"), as supplemented by Resolution No. 2612 of the District, adopted on May 13, 2013 (the "First Supplemental Resolution," and together with the 2003 Resolution, the "Resolution") to provide the funds to refund the District's outstanding Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 (the "2003 Bonds") maturing on and after October 1, 2014 and pay costs of issuing the 2013 Bonds. See "PURPOSE OF THE 2013 BONDS AND APPLICATION OF THE 2013 BOND PROCEEDS."

Bonds issued pursuant to the Resolution are referred to as the "Cowlitz Falls Bonds." No Cowlitz Falls Bonds other than the 2003 Bonds are currently outstanding under the Resolution.

The District is a municipal corporation under the constitution and laws of the State of Washington. The District was organized in 1936 pursuant to a general election and commenced operation in 1939. The District has its administrative offices in Chehalis, Washington and is governed by a three-member Board of Commissioners. In addition to the Cowlitz Falls Project, the District also owns and operates an electric distribution system (the "Electric System"), which is financed and accounted for separately from the Cowlitz Falls Project. The Electric System serves substantially all of Lewis County, Washington, except the City of Centralia. See "THE DISTRICT."

Bonneville Power Administration

In 1991, the United States of America, Department of Energy ("DOE"), acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), entered into a Power Purchase Contract with the District under which Bonneville is acquiring all of the output of the Cowlitz Falls Hydroelectric Project (the "Project" or "Cowlitz Falls Project") through June 30, 2032 (the "Power Purchase Contact"). Pursuant to the Power Purchase Contract, Bonneville is obligated to pay all Project Power Costs (as defined in the Power Purchase Contract), including debt service on the Cowlitz Falls Bonds, including the 2003 Bonds and the 2013 Bonds, whether or not the Cowlitz Falls Project is terminated, operating or operable. Bonneville also entered into a Payment Agreement with the Trustee in 1991 under which Bonneville is further obligated to pay debt service on the Cowlitz Falls Bonds if Bonneville does not make such payments under the Power Purchase Contract. The Power Purchase Contract and the Payment Agreement are referred to as the "Cowlitz Falls Agreements." See Appendix D – "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT."

The remainder of this Introduction has been derived from information provided to the District by Bonneville. For detailed information with respect to Bonneville, see Appendix A—"BONNEVILLE POWER ADMINISTRATION."

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 31 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation ("Reclamation"), and from several non-federally-owned projects, including the Cowlitz Falls Project and the Columbia Generating Station. Bonneville sells and/or exchanges power under contracts with over 125 utilities in the Pacific Northwest and Pacific Southwest and with several industrial customers. It also owns and operates a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest.

Bonneville's primary customer service area is the Pacific Northwest region, an area comprised of Oregon, Washington, Idaho, parts of western Montana and small portions of northern California, northern Nevada, northern Utah and western Wyoming (sometimes referred to herein as the "Pacific Northwest," the "Northwest," the "Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately 12 million people. Electric power sold by Bonneville accounts for more than one-third of the electric power consumed within the Region. Bonneville also exports power that is surplus to the needs of the Region to the Pacific Southwest, primarily to California.

Bonneville is one of four regional Federal power marketing agencies within the DOE. Bonneville is required by law to meet certain energy requirements in the Region and is authorized to acquire power resources, to implement conservation measures and to take other actions to enable it to carry out its purposes. Bonneville is also required by law to operate and maintain its transmission system and to provide transmission service to eligible customers and to undertake certain other programs, such as fish and wildlife protection, mitigation and enhancement.

PURPOSE OF THE 2013 BONDS AND APPLICATION OF THE 2013 BOND PROCEEDS

Purpose of the 2013 Bonds

Proceeds of the 2013 Bonds will be used to refund all of the District's outstanding 2003 Bonds maturing on and after October 1, 2014 and to pay the costs of issuing the 2013 Bonds. The 2003 Bonds so refunded are referred to as the "Refunded Bonds." All of the Refunded Bonds will be redeemed on October 1, 2013 at the redemption price of 100% of the principal amount plus accrued interest, if any, to the redemption date.

Proceeds of sale of the 2013 Bonds, and additional funds, shall be credited to the Refunding Account, to be held by U.S. Bank National Association (the "Escrow Agent") under an escrow agreement (the "Escrow Agreement"), dated the date of delivery of the 2013 Bonds, between the District and the Escrow Agent, which is to be drawn upon for the sole purpose of paying the principal of and interest on the Refunded Bonds on their date of redemption and paying costs related to the refunding of the Refunded Bonds. Money in the Refunding Account shall be used immediately upon receipt to defease the Refunded Bonds and to pay costs of issuing the 2013 Bonds. Money deposited in the Refunding Account may be invested in U.S. Treasury obligations that will mature on or prior to October 1, 2013, the date of redemption.

Estimated Sources and Uses of Funds

The proceeds from the 2013 Bonds are estimated to be applied as follows:

Sources of Funds	**Total**
Principal Amount of the 2013 Bonds	$ 87,995,000
Net Original Issue Premium	12,278,112
Other Available Funds	1,215,764
Total	$ 101,488,876
Uses of Funds	
Deposit to Refunding Account	$ 100,561,538
Costs of Issuance (including Underwriters' compensation)	927,338
Total	$ 101,488,876

Verification of Mathematical Calculations

The accuracy of the mathematical computations as to the adequacy of the principal of and interest on the cash held by the Escrow Agent to pay the redemption price of and interest on the Refunded Bonds as described above will be verified by Causey Demgen & Moore, P.C., Denver, Colorado.

SECURITY FOR THE 2013 BONDS

Pledge of Cowlitz Falls Revenues

The 2013 Bonds are special limited obligations of the District payable from and secured solely by: (i) a pledge of and lien on Cowlitz Falls Revenues, which include income, revenues, receipts and profits derived by the District in connection with the Cowlitz Falls Project, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Project and certain other money, including amounts paid by Bonneville under the Power Purchase Contract, exclusive of any payments under the Payment Agreement, certain insurance proceeds, and income pledged to the defeasance of specific revenue bonds (see Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution" for the complete definition of Cowlitz Falls Revenues); and (ii) the money and assets, if any, credited to the Revenue Fund, the Bond Fund, any junior lien fund or account created pursuant to the Resolution, in each case excluding amounts required to be rebated to the Federal government. See "THE BONNEVILLE FUND" and Appendix A for a description of the source of Bonneville's payments and other information regarding Bonneville. Such items are pledged as security for the payment of the principal of, redemption premium, if any, and interest on the 2013 Bonds in accordance with the provisions of the Resolution, subject only to the provisions restricting or permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution. The 2013 Bonds are further secured by payments, if any, made by Bonneville to the Trustee pursuant to the Payment Agreement. **Cowlitz Falls Revenues do not include any payments, if any, made by Bonneville to the Trustee pursuant to the Payment Agreement. The Cowlitz Falls Bonds are not payable from, or secured by any lien on, or any income derived by the District through the ownership and operation of, the Electric System or any other generation, transmission or distribution facilities that may be purchased, constructed or otherwise acquired by the District as a separate system.**

Upon the issuance of the 2013 Bonds, the only other Outstanding Cowlitz Falls Bonds will be the October 1, 2013 maturity of the 2003 Bonds. The outstanding 2003 Bonds, the 2013 Bonds and any bonds issued on a parity therewith (the "Additional Bonds") shall be equally and ratably payable and secured under the Resolution without priority, except as otherwise expressly provided or permitted in the Resolution and except as to proceeds of credit enhancements which may be obtained by the District to assure the repayment of one or more series or maturities within a series.

Power Purchase Contract

The District and Bonneville entered into the Power Purchase Contract to provide for the acquisition, construction, improvement and operation of the Cowlitz Falls Project and to provide for the sale of the electric power to be generated by the Cowlitz Falls Project. The original Power Purchase Contract became effective January 28, 1991, was restated effective May 23, 1991, was amended on October 24, 2002 and terminates on June 30, 2032. See Appendix D – "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT" for a summary of certain of the provisions of the Cowlitz Falls Agreements and defined terms used herein.

In the Power Purchase Contract, the District agrees to sell and deliver, and Bonneville agrees to purchase and accept delivery of, the entire Project output during the Term of the Power Purchase Contract. Bonneville has agreed to pay during each Operating Year an amount equal to Cowlitz Falls Project Power Costs, including debt service on the Cowlitz Falls Bonds, whether or not the Project or any part thereof has been completed, terminated, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance of any party or for any cause. In accordance with the Resolution and the Cowlitz Falls Agreements, Bonneville shall pay to the Trustee amounts sufficient to pay principal of, premium, if any, and interest on the Cowlitz Falls Bonds. Such payments shall be made solely from the Bonneville Fund. See Appendix A—"BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund." In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville, including a breach of the Power Purchase Contract, is a judgment for money damages.

Cowlitz Falls Project Power Costs means, with respect to each month, an amount equal to all costs attributable to the Cowlitz Falls Project, to the extent not paid from the proceeds of Cowlitz Falls Bonds or any other sources, resulting from the ownership, operation, maintenance and improvement of the Cowlitz Falls Project. The District is not obligated and does not expect to pay Cowlitz Falls Project Power Costs from Electric System Revenues.

Payment Agreement

If, and to the extent that, Bonneville does not make payments of principal of, interest on, and premium, if any, on the Cowlitz Falls Bonds under the Power Purchase Contract at the time and in the manner described in the Power Purchase Contract, Bonneville is required to make payments under the Payment Agreement not later than the dates on which such payments are described by the Power Purchase Contract. To the extent the amounts required to be paid under the Resolution as principal of and interest on the Cowlitz Falls Bonds will not be available in the Bond Fund to be paid when due, Bonneville is required to make such payments to the Trustee for benefit of the bondowners. Such payments are to be made only from the Bonneville Fund as described herein or from such other funds as shall now or hereafter become lawfully available for such purposes. See "THE BONNEVILLE FUND." Bonneville agrees in the Payment Agreement that its obligations and the rights of the Trustee and the bondowners under the Payment Agreement shall not be terminated, impaired, or otherwise affected by any action taken, or not taken, by the District, the Trustee, any bondowner or any other party. The Payment Agreement remains in full force and effect whether or not the Project or any part thereof has been completed, terminated, is operating or operable or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. The Trustee has the authority to enforce the provisions of the Payment Agreement and to protect the interest of the bondowners in the manner provided by law. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville, including a breach of the Payment Agreement, is a judgment of money damages. The Payment Agreement remains in full force and effect without impairment of any of Bonneville's obligations until the date on which all Cowlitz Falls Bonds have been paid or defeased in accordance with the Resolution. See Appendix D – "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT."

Flow of Funds

The District has covenanted that so long as any of the Cowlitz Falls Bonds are outstanding and unpaid it will continue to pay into the Revenue Fund all Cowlitz Falls Revenues, except for payments made directly by Bonneville to the Trustee pursuant to the Power Purchase Contract or the Payment Agreement (which payments are to be deposited directly into the Bond Fund), and any other money required to be paid into the Revenue Fund pursuant to

the Resolution. So long as any Cowlitz Falls Bonds remain outstanding, the amounts on deposit in the General Account in the Revenue Fund and the Bond Fund, as applicable, are to be used only for the following purposes and in the following order of priority:

(i) to make all payments required to be made into the Interest Account in the Bond Fund;

(ii) to make all payments required to be made into the Principal Account in the Bond Fund;

(iii) to make all payments required to be made into the Reserve Account in the Bond Fund, including reimbursing the provider for any draws on Qualified Insurance or a Qualified Letter of Credit;

(iv) to pay Operation and Maintenance Costs;

(v) to make all payments required to be made into any junior lien fund or account; and

(vi) to make any payments required to be made into the Reserve and Contingency Account in the Revenue Fund.

After all of the above payments and credits have been made, amounts remaining in the General Account may be used for any of the following purposes: (i) for transfer to any other fund or account created under the Resolution; (ii) for the purchase or redemption of any Cowlitz Falls Bonds; (iii) to pay any subordinated indebtedness of the Cowlitz Falls Project; (iv) to pay Other Renewal and Replacement Costs; or (v) for any lawful corporate purpose of the District; provided that during the Term of the Cowlitz Falls Agreements all surplus amounts in the General Account shall be used for the Cowlitz Falls Project as directed by Bonneville.

There are currently no payments required to be made into the Reserve and Contingency Account.

Reserve Account

A Reserve Account is established in the Bond Fund to provide a reserve for the payment of the principal of, premium, if any, and interest on the Cowlitz Falls Bonds. The Reserve Account will not be funded for the 2003 Bonds or the 2013 Bonds. For a summary of provisions relating to the Reserve Account, see Appendix C – "SUMMARY OF THE RESOLUTION – Reserve Account."

Additional Bonds

The District has no current plans to issue any Additional Bonds. The Resolution permits the issuance of Additional Bonds payable from Cowlitz Falls Revenues on a parity with the Cowlitz Falls Bonds upon compliance with the following conditions:

1. That when such Additional Bonds are issued there is no deficiency in the Bond Fund or in any of the accounts therein and no Event of Default has occurred and is continuing; and

2. There shall be on file a certified copy of the Supplemental Resolution authorizing the issuance of such Additional Bonds; and

3. Bonneville shall have approved the issuance of the Additional Bonds; and

4. Either (a) debt service on the whole of the Additional Bonds is payable as a Project Power Cost under the Power Purchase Agreement for at least the term of the Power Purchase Agreement (or the final maturity date of such Additional Bonds if such maturity date shall occur earlier than the end of such term), or (b) debt service on the whole of the Additional Bonds is not payable as a Project Power Cost under the Power Purchase Agreement and that, except for refunding Bonds where there is a debt service savings in each year (as to which no report of the Consulting Engineer is required), there shall have been delivered to the Trustee and the District a report of a Consulting Engineer, to the effect that the plan pursuant to which the proceeds of such Bonds are to be expended is

consistent with prudent utility practice and will not adversely materially interfere with the operations of the Cowlitz Falls Project and that in the opinion of the Consulting Engineer, based on such assumptions as he or she believes to be reasonable, such plan will not result in a reduction of Cowlitz Falls Revenues below the amount sufficient for the payment of Cowlitz Falls Project Power Costs, after crediting against such costs amounts paid from the Reserve and Contingency Account or from Recovery Payments or other insurance proceeds; and

5. There shall be on file an opinion of Bond Counsel that the Additional Bonds are validly issued and constitute an enforceable and binding obligation of the District, except as such enforceability may be limited by laws affecting the rights of creditors or equitable principles.

With the consent of Bonneville, the District may enter into Derivative Products under which its payment obligations are on a parity with the Cowlitz Falls Bonds. See Appendix C – "SUMMARY OF THE RESOLUTION – Additional Bonds." The District has not entered into any Derivative Products.

Covenants

For a summary of certain covenants of the District, see Appendix C – "SUMMARY OF THE RESOLUTION – Covenants."

THE BONNEVILLE FUND

Payments by Bonneville under the Cowlitz Falls Agreements are to be made from the Bonneville Fund. **Bonneville's payment obligations under the Cowlitz Falls Agreements 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 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 appropriation acts, for any purposes necessary or appropriate to carry out of the duties imposed upon Bonneville pursuant to law.

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 2012 payment responsibility to the United States Treasury in full and on time for the 29th 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, including debt service on the Cowlitz Falls Bonds. 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 has used a power prepayment program, which has similar effects on Bonneville's revenues in cash as occurs under net billing. Under the power prepayment, in return for up-front lump sum prepayments of power by Bonneville's customers, Bonneville has agreed to provide fixed credits to their power purchases through September 30, 2028. 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—Energy Northwest Direct Pay Agreements," and "—CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE FINANCIAL OPERATIONS—2013 Prepaid Power Program."

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. 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 for debt service on the outstanding Cowlitz Falls Bonds under the Cowlitz Falls Agreements, 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."

DESCRIPTION OF THE 2013 BONDS

Description

The 2013 Bonds will be dated their date of delivery to the Underwriters and will be issued in the aggregate principal amount of $87,995,000. The 2013 Bonds will mature on the dates and in the principal amounts and will bear interest at the respective rates as shown on the inside cover page of this Official Statement. The 2013 Bonds will be issued as registered bonds in multiples of $5,000 within a single maturity and will be in a book-entry only system, initially registered in the name of Cede & Co., as nominee for The Depository Trust Company ("DTC"), New York, New York. See Appendix H – "BOOK-ENTRY ONLY SYSTEM." Interest on the 2013 Bonds will be paid on October 1, 2013, and semiannually thereafter on each April 1 and October 1 to maturity or prior redemption. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

Registrar

The principal of, premium, if any, and interest on the 2013 Bonds are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Registrar"). For so long as the 2013 Bonds remain in book-entry only form, the Registrar will make such payments to DTC, which, in turn, is obligated to remit such principal and interest to DTC participants for subsequent disbursement to the Beneficial Owners of the 2013 Bonds as further described in Appendix H – "BOOK-ENTRY ONLY SYSTEM."

The District and Bonneville have appointed U.S. Bank National Association, a national banking association organized under the laws of the United States, to serve as Trustee. The Trustee is to carry out those duties assigned under the Resolution. Except for the contents of this section, the Trustee has not reviewed or participated in the preparation of this Official Statement and assumes no responsibility for the contents, accuracy, fairness or completeness of the information set forth in this Official Statement or for the recitals contained in the Resolution or the 2013 Bonds, or for the validity, sufficiency, or legal effect of any of such documents.

The Trustee has not evaluated the risks, benefits, or propriety of any investment in the 2013 Bonds and makes no representation, and has reached no conclusions, regarding the value or condition of any assets or revenues pledged or assigned as security for the 2013 Bonds, or the investment quality of the 2013 Bonds, about all of which the Trustee expresses no opinion and expressly disclaims the expertise to evaluate.

Additional information about the Trustee may be found at its website at http://www.usbank.com/corporatetrust.

Redemption

Optional Redemption. The 2013 Bonds stated to mature on October 1 in years 2014 through 2023, inclusive, are not subject to redemption at the option of the District prior to maturity. The 2013 Bonds stated to mature on or after October 1, 2024 are subject to redemption at the option of the District, in whole or in part, on any date on or after October 1, 2023 at a price equal to the stated principal amount to be redeemed, plus accrued interest, if any, to the date fixed for redemption.

Selection of 2013 Bonds for Redemption. If fewer than all of the outstanding 2013 Bonds are to be redeemed at the option of the District, the District, with the consent of Bonneville, shall select the maturities to be redeemed. If fewer than all of the outstanding 2013 Bonds of a maturity are to be redeemed, 2013 Bonds registered in the name of DTC or its nominee shall be redeemed in accordance with the Letter of Representations, and all other 2013 Bonds shall be selected by the Registrar for redemption randomly in such manner as the Registrar shall determine.

Partial Redemption. If less than all of the principal amount of any 2013 Bond is redeemed, upon surrender of such 2013 Bond at the principal office of the Registrar, there shall be issued to the registered owner, without charge, for the then unredeemed balance of the principal amount, a new 2013 Bond or 2013 Bonds, at the option of the registered owner, of like maturity and interest rate in any authorized denomination.

Notice of Redemption. Written notice of any redemption of 2013 Bonds shall be given by the Registrar on behalf of the District by first class mail, postage prepaid, not less than 20 days nor more than 60 days before the redemption date to the registered owners of 2013 Bonds that are to be redeemed at their last addresses shown on the Bond Register. So long as the 2013 Bonds are in book-entry form, notice of redemption shall be given as provided in the Letter of Representations.

In the case of an optional redemption, the notice of redemption may state that the District retains the right to rescind the redemption notice and the optional redemption of those 2013 Bonds by giving a notice of rescission to the affected Registered Owners at any time prior to the scheduled optional redemption date. Any notice of optional redemption that is so rescinded shall be of no effect, and a 2013 Bond for which a notice of optional redemption has been rescinded shall remain outstanding.

Effect of Redemption. Unless the District has rescinded a notice of redemption, the District is required to transfer to the Registrar amounts that, in addition to other money, if any, held by the Registrar, will be sufficient to redeem, on

the redemption date, all the 2013 Bonds to be redeemed. Interest on each 2013 Bond to be redeemed shall cease to accrue on the redemption date.

Purchases for Cancellation

The District has reserved the right, with the consent of Bonneville, to purchase any of the 2013 Bonds offered to the District at any price deemed reasonable by the District at any time.

Transfer and Registration

The registered ownership of any 2013 Bond may be transferred or exchanged, but no transfer of any 2013 Bond shall be valid unless it is surrendered to the Registrar with the assignment form appearing on such 2013 Bond duly executed by the Registered Owner or such Registered Owner's duly authorized agent in a manner satisfactory to the Registrar. Upon such surrender, the Registrar shall cancel the surrendered 2013 Bond and shall authenticate and deliver, without charge to the Registered Owner or transferee, a new 2013 Bond (or 2013 Bonds at the option of the new Registered Owner) of the same date, maturity and interest rate and for the same aggregate principal amount in any authorized denomination, naming as Registered Owner the person or persons listed as the assignee on the assignment form appearing on the surrendered 2013 Bond, in exchange for such surrendered and canceled 2013 Bond. Any 2013 Bond may be surrendered to the Registrar and exchanged, without charge, for an equal aggregate principal amount of 2013 Bonds of the same date, maturity and interest rate, in any authorized denomination. The Registrar shall not be obligated to transfer or exchange any 2013 Bond during a period beginning at the opening of business on the 15th day of the month preceding the maturity of such 2013 Bond or, in the case of any proposed redemption of the 2013 Bonds, after mailing of notice of the call of such 2013 Bonds for redemption.

Termination of Book-Entry Only System

In the event that (i) DTC or its successor (or substitute depository or its successor) resigns from its functions as depository, and no substitute depository can be obtained, or (ii) the District determines that any 2013 Bonds be issued in certificated form, the ownership of such 2013 Bonds may then be transferred to any person or entity as provided in the Resolution, and shall no longer be held in book-entry only form. The District shall deliver a written request to the Registrar, together with a supply of definitive 2013 Bonds in certificated form, to issue 2013 Bonds in any authorized denomination. Upon receipt by the Registrar of all such outstanding 2013 Bonds, together with a written request on behalf of the District to the Registrar, new 2013 Bonds shall be issued in the appropriate denominations and registered in the names of such persons as are provided in such written request. Thereafter, interest on each 2013 Bond shall be paid by check or draft mailed to the Registered Owner at the address appearing on the Bond Register on the Record Date, and principal of each 2013 Bond shall be payable upon presentation and surrender of such 2013 Bond by the Registered Owner at the designated corporate trust office of the Registrar; provided, however, that if so requested in writing by the Registered Owner of at least $1,000,000 principal amount of 2013 Bonds, interest will be paid by wire transfer on the date due to an account with a bank located within the United States.

DEBT SERVICE REQUIREMENTS

Proceeds of the 2013 Bonds will be used to refund all of the outstanding 2003 Bonds maturing on and after October 1, 2014, and to pay the costs of issuing the 2013 Bonds. Debt service on the 2013 Bonds, rounded to the nearest dollar, is set forth below.

Debt Service Requirements[1]

Year	Principal	Interest	Total*
2013	--	$ 980,598	$ 980,597
2014	$ 2,940,000	4,358,213	7,298,213
2015	3,000,000	4,299,412	7,299,412
2016	3,150,000	4,149,413	7,299,413
2017	3,310,000	3,991,912	7,301,912
2018	3,475,000	3,826,413	7,301,413
2019	3,650,000	3,652,662	7,302,662
2020	3,830,000	3,470,163	7,300,163
2021	4,020,000	3,278,662	7,298,662
2022	4,220,000	3,077,663	7,297,663
2023	4,435,000	2,866,662	7,301,662
2024	4,655,000	2,644,913	7,299,913
2025	4,900,000	2,400,525	7,300,525
2026	5,155,000	2,143,275	7,298,275
2027	5,430,000	1,872,638	7,302,638
2028	5,710,000	1,587,562	7,297,562
2029	6,010,000	1,287,788	7,297,788
2030	6,330,000	972,262	7,302,262
2031	6,660,000	639,938	7,299,938
2032	7,115,000	186,769	7,301,769
Total*	**$87,995,000**	**$ 51,687,442**	**$ 139,682,442**

(1) The table does not include the October 1, 2013 maturity of the 2003 Bonds that will not be refunded with proceeds of the 2013 Bonds.

* Totals may not foot due to rounding.

THE COWLITZ FALLS PROJECT

Description of the Cowlitz Falls Project

The Cowlitz Falls Project was built on the upper Cowlitz River in eastern Lewis County, Washington, approximately one mile below the confluence of the Cispus River and the Cowlitz River and upstream from the existing Mayfield and Mossyrock hydroelectric projects owned and operated by the City of Tacoma, Washington. The dam and power generation facility were completed in 1994. The dam is 140 feet high and spans approximately 700 feet across the Cowlitz River. A reservoir behind the dam has a surface area of approximately 610 acres. The powerhouse contains two vertical Kaplan-type turbine units connected to two synchronous generators, each with a rated capacity of approximately 35 megawatts, at an average net head of approximately 87.5 feet.

In June 1986, the District was granted a 50-year license by the Federal Energy Regulatory Commission ("FERC") to construct and operate the Cowlitz Falls Project. The license expires on June 1, 2036.

Cowlitz Falls Project Output

The Cowlitz Falls Project has minimal storage capability. Consequently, it is operated essentially as a "run-of-river" hydroelectric facility, and daily variations in the water surface elevation of the reservoir are not expected to exceed two feet under normal operating conditions.. The amount of energy generated by the Cowlitz Falls Project is

affected by a number of factors, including natural stream flows and FERC requirements. Estimates of expected energy generation at hydroelectric power projects in the Pacific Northwest for planning purposes are generally based on historical stream flows which occurred over the longest period for which historical stream flow records are available. Based on a 57-year period (1928 through 1985) of historical stream flow records which the District used for planning purposes, the annual energy output of the Cowlitz Falls Project would have varied from a low of approximately 136,000 megawatt-hours ("MWh") based on stream flows which occurred in 1941 to a high of approximately 375,000 megawatt-hours based on stream flows which occurred in 1956. The average annual energy output (including non-firm energy) of the Cowlitz Falls Project which would have been produced during the 57-year period is approximately 260,000 MWh. Over the past five years, the Cowlitz Falls Project on average has produced 246,457 MWh annually with a low of 217,287 in 2011 and a high of 305,267 in 2012.

Cowlitz Falls Project Annual Costs

The following table sets forth the amount of power and cost of power from the Cowlitz Falls Project which was delivered to Bonneville at the point of delivery in 2008 to 2012.

Cowlitz Falls Project Output and Annual Cost of Power
($000)*

	2008	2009	2010	2011	2012
PROJECT POWER COSTS					
Operation and Maintenance Expenses:					
Operation [1]	$ 1,273	$ 1,088	$ 1,423	$ 1,446	$ 1,467
Maintenance [1]	731	988	1,582	737	1,049
Taxes [2]	97	107	111	104	134
Extraordinary Expense – Flood[3]	0	0	0	1,449	0
Subtotal	$ 2,102	$ 2,184	$ 3,115	$ 3,736	$ 2,650
Debt Service on Bonds[4]	$11,711	$11,705	$11,707	$11,711	$11,715
Less: Interest Earnings[5]	$ 12	$ 5	$ 3	$ 2	$ 2
Other Income	12	81	1	(159)	92
Grant and Insurance Proceeds	0	0	0	1,290	0
Net Debt Service	$11,687	$11,620	$11,703	$10,575	$11,621
Total Project Power Costs	$13,789	$13,804	$14,818	$14,311	$14,271
TRANSMISSION COSTS [6]	$ 859	$ 871	$ 871	$ 871	$ 871
TOTAL ANNUAL COST OF PROJECT POWER TO BONNEVILLE	$14,648	$14,675	$15,689	$15,182	$15,142
Net Energy Output Delivered to Bonneville (MWh) [7]	224,141	233,491	252,097	217,287	305,267
Average Net Energy Cost (cents/MWh)[8]	$65.30	$62.80	$62.30	$69.90	$49.60

(1) The District currently is not capitalizing any expenditures and records expenses as incurred.
(2) Includes State privilege taxes on the generation output and other taxes incurred by the Project.
(3) In late 2006, there was a flood in the Cowlitz River Basin and, in response, the sluice gate was modified to improve its performance.
(4) Consists of debt service on the 2003 Bonds, which is paid pursuant to an amortization schedule and includes principal and interest.
(5) Interest earnings are from funds placed in the debt service account for the 2003 Bonds according to bond covenants.
(6) The District's annual costs of wheeling the Project output from the Glenoma substation to the Bonneville transmission system, which includes costs incurred from transmission over Tacoma lines.
(7) Annual changes are primarily due to variations in stream-flow.
(8) Average net cost to Bonneville at the point of delivery.
* Totals may not add due to rounding.

Moss Adams, the District's auditor, has not reviewed or performed any procedures with respect to this Official Statement.

Transmission of Cowlitz Falls Project Output

Cowlitz Falls Project output is delivered from the Project switchyard to the Bonneville point of delivery over a five mile 230 kV transmission line from the Project switchyard to the District's Glenoma substation, then over a 15 mile 230-kV transmission line from the Glenoma substation to an existing switchyard owned by the City of Tacoma

(Mossyrock switchyard) at the Mossyrock Dam site, and finally from the Mossyrock switchyard over existing transmission facilities of the City of Tacoma to the Bonneville point of delivery, which is located approximately six miles from the Mossyrock switchyard.

Environmental Issues

In the late 1990's, the National Oceanographic and Atmospheric Administration — Fisheries ("NOAA Fisheries") listed the lower Columbia Chinook salmon and steelhead trout as threatened under the Endangered Species Act ("ESA"). The Cowlitz River is a tributary of the lower Columbia River and the Cowlitz Falls Project operates on the Cowlitz. As a result of the Cowlitz Falls Project operation and the ESA anadromous fish listings, the District initiated consultation with the FERC and NOAA Fisheries to evaluate possible ESA impacts on the Project. The consultation led to a permitted taking of the threatened species for the Project.

Bonneville, in cooperation with the District, state and federal agencies and Tacoma Power, constructed a downstream anadromous fish collection facility at the Cowlitz Falls Dam in the 1990s. The fish facility has permitted the reintroduction of salmon and steelhead in the upper Cowlitz River basin. The upper Cowlitz and Cispus River basins were blocked from migrating salmon and steelhead by Tacoma Power's construction of the Mossyrock and Mayfield Dams in the 1960's. The District, Bonneville and Tacoma Power are involved in efforts to improve the anadromous fish reintroduction program for the upper Cowlitz River. Tacoma Power is proposing to construct a fish collection facility adjacent to the Cowlitz Falls Fish Facility.

THE DISTRICT

General

The District is a municipal corporation of the State of Washington. The District was organized in 1936 pursuant to a general election in accordance with Title 54 RCW and commenced its operations in 1939. The District's service territory is comprised of approximately 2,530 square miles in Lewis County, Washington, as well as a portion of southeastern Pierce County in the vicinity of Mt. Rainier National Park. The District does not serve the City of Centralia, which is located in Lewis County. The District's administrative offices are located at 321 N.W. Pacific Avenue, P.O. Box 330, Chehalis, Washington 98532.

Pursuant to Washington statutes, the District is administered by a Board of Commissioners (the "Commission") of three elected members. The legal responsibilities and powers of the District, including the establishment of rates and charges for services rendered, are exercised through the Commission. The Commission establishes policy, approves plans, budgets and expenditures and reviews the District's operations. Under present law, the District has the exclusive authority to set rates and charges for electric energy and services and is by law free from the rate-making jurisdiction and control of the Washington Utilities and Transportation Commission or any other state, federal or local agency having the authority to set rates and charges for electric energy and services. The District has the power of eminent domain.

The present Commissioners of the District, their titles and the expiration dates of their respective terms of office are as follows:

Name	Title	Expiration of Term of Office December 31,
Ben M. Kostick	President	2014
Charles R. TenPas	Vice President	2016
Dean Dahlin	Secretary	2018

Ben M. Kostick, President, was appointed to the Commission in 2007 and is currently serving his first term as a Commissioner. Mr. Kostick is a self-employed certified public accountant.

Charles R. TenPas, Vice President, was appointed to the Commission in June 1995 and is serving his third term on the Commission. Mr. TenPas currently serves as the District's representative to the Washington Public Utility District Association and is a retired public school teacher and administrator.

Dean Dahlin, Secretary, was elected to the Commission beginning January 2013 and is serving his first term. Mr. Dahlin is a retired locomotive engineer and active weatherman.

Management and Administration

The principal staff members of the District are as follows:

Robert D. Geddes, Manager, joined the District in 2011. Previously, Mr. Geddes served as General Manager of Public Utility District No. 1 of Pend Oreille County for 11 years, and Director of Regulatory and Environmental Affairs for five years prior to that. Mr. Geddes began his utility career as a District Commissioner for 12 years. He is past president of the Washington Public Utility District Utilities System (now Public Utility Risk Management Services), past chair of the Public Generating Pool, and completed a term a chair of the Managers' Section of the Washington Public Utility District Association. He is involved in various state and local entities and has served as President of the local Rotary Club. He holds a Bachelor of Arts degree in Journalism from Western Washington University.

Richard L. Bauer, ***CPA***, Treasurer/Chief Financial Officer, joined the District in 2000. Prior to joining the District, Mr. Bauer was the Auditor/Office Manager of Public Utility District No. 1 of Ferry County, Washington. Mr. Bauer is currently chair of the Operations Committee for the Public Utility Risk Management Services ("PURMS"). Mr. Bauer has served as President of the local Lions Club and is involved with trade associations. He holds a Bachelor of Science degree in accounting from Central Washington University, Bachelor of Arts degree in Business Administration from Western Washington University and is certified under the Laws of the State of Washington as a licensed Certified Public Accountant.

Bradley J. Ford, Auditor, joined the District in 2012. Prior to joining the District, Mr. Ford was the Finance Director of the City of Centralia. Mr. Ford holds a Bachelor of Business Administration degree in Finance from Idaho State University and a Post-Baccalaureate Accounting Certificate from Portland State University.

Greg Hart, Superintendent, joined the District in 2010. Prior to joining the District, Mr. Hart was a self employed contractor contracting with various electric utilities. Mr. Hart has a combined experience of over 41 years in the electric industry holding various positions with Kootenai Electric Cooperative and others.

Labor Relations

The District had 103 full time employees and 3 part time employees as of December 31, 2012. The District has two separate agreements with the International Brotherhood of Electrical Workers ("IBEW"), one covering union employees of the Electric System and a second covering the union employees of the Cowlitz Falls Project. The term of the Electric System agreement with the IBEW is three years and expires on March 31, 2015. The Cowlitz Falls Project agreement with the IBEW expires on March 31, 2015.

Utility Operations

The District's electric utility properties and operations presently consist of two separate systems, each of which is accounted for and financed separately. The systems are (1) the Electric System, which includes the electric utility properties and assets used generally in transmitting and distributing electric energy at retail and (2) the Cowlitz Falls Project (see "THE COWLITZ FALLS PROJECT").

The Electric System's operations, maintenance and capital additions are financed from revenues received from the sale of electricity. The Electric System has $31,930,000 in outstanding debt, which is secured by revenues of the Electric System and not by Bonneville. The Electric System's net utility plant as of December 31, 2012 was $116

million. In 2012, the Electric System had operating revenues of $62 million, net income of $1.6 million and retained earnings of $13.4 million. The District received audited 2012 financials in late May 2013.

The District serves approximately 30,942 customers, of which more than 25,600 are residential. Historically, Lewis County's economy has been based on the timber and agricultural industries. In recent years, Lewis County's employment has experienced a transition toward governmental services, retail trade and service industries generally related to Interstate Highway 5 that crosses the western part of Lewis County. Today, the District's retail sales consist of residential (approximately 54%), industrial (approximately 22%), commercial (approximately 17%), and public and governmental authorities (approximately 7%). In 2012, the Hardel Mutual Plywood Company was the District's largest customer, purchasing approximately $1,465,300 worth of power.

Power Supply

In 2012, the District obtained approximately 91.1% of its power from Bonneville, 5.4% from the White Creek Wind Project, 1.6% from Energy Northwest's Nine Canyon Wind Project, 1.6% from Energy Northwest's Packwood Project and 0.3% from other sources.

Effective October 1, 2011, the District entered into a Block/Slice Agreement with Bonneville that terminates on September 30, 2028. The Block/Slice Agreement commits the District to purchase a certain block of power (45,994 aMW) as well as a slice or certain fixed percentage of Bonneville generation (0.96%), which varies depending on the available water and may result in power that is surplus to the District's needs and which the District intends to sell on the open market.

The District owns, operates, and utilizes the power from a small 600 kW hydroelectric project (Mill Creek). The District has signed two power purchase agreements with Energy Northwest: the first for 2% (one MW of capacity) of the output of Nine Canyon Wind Project Phase I, which began commercial operation in 2002, and the second for 15.7% (five MW of capacity) of the output of Nine Canyon Wind Project Phase III, which began commercial operation in 2008. The District executed 20-year agreements with Klickitat County PUD in 2008 for the acquisition of a 10% share of the output of the 205 MW White Creek Wind Project near Goldendale, Washington for $36.85 million. Pursuant to a Power Sales Contract entered into by the District with Energy Northwest, the District has purchased 14.25% of the output of the Packwood Project and is obligated to pay Energy Northwest the same percentage of the annual cost thereof.

In 2011, the District entered into a power management services agreement with The Energy Authority ("TEA") to provide certain power scheduling, purchasing, sales, and related services to assist in the short term management of the District's power supply.

Insurance

The District and 16 other public utility districts participate in a joint self-insurance pool ("Fund") in affiliation with Public Utility Risk Management Services ("PURMS"), formerly Washington Public Utility Districts' Utilities System. The PURMS Fund self insures its members to $500,000 for liability and maintains a reserve of at least $1,000,000. Members of the PURMS Fund are automatically assessed to make up any shortfall in the reserve amount. General comprehensive liability insurance in excess of $500,000 is insured through Associated Electric and Gas Insurance Services Limited in the amount of $35,000,000. Public officials' errors and omissions liability is issued to the District in the amount of $4,500,000 in excess of the $500,000 self-insurance fund. The PURMS Fund and its members are involved in ongoing litigation and claim processing of which the total dollar value of the risk posed is unknown. Currently, the Cowlitz Falls Project is insured separate from the Electric System through Factory Mutual Insurance Company (FM Global). The dam structure is insured to $100,000,000 along with other coverage for operating activities and liabilities.

LITIGATION

There is no litigation pending or threatened in any court (local, state or federal) to restrain or enjoin the issuance or delivery of the 2013 Bonds, or questioning the creation, organization, existence, or title to office of the officers of

the District, the validity or enforceability of the 2013 Bonds or the Resolution, the pledge of Cowlitz Falls Revenues or the proceedings for the authorization, execution, sale and delivery of the 2013 Bonds. For a discussion of certain litigation involving Bonneville, see Appendix A—"BONNEVILLE POWER ADMINISTRATION – BONNEVILLE LITIGATION."

LEGAL MATTERS

Legal matters incident to the authorization, issuance and sale of the 2013 Bonds by the District are subject to the approving legal opinion of Foster Pepper PLLC, Seattle, Washington, Bond Counsel. The form of the opinion of Bond Counsel with respect to the 2013 Bonds is attached as Appendix E. The opinion of Bond Counsel is given based on factual representations made to Bond Counsel, and under existing law, as of the date of initial delivery of the 2013 Bonds, and Bond Counsel assumes no obligation to revise or supplement its opinion to reflect any facts or circumstances that may thereafter come to its attention, or any changes in law that may thereafter occur. The opinion of Bond Counsel is an expression of its professional judgment on the matters expressly addressed in its opinion and does not constitute a guarantee of result. Bond Counsel will be compensated only upon the issuance and sale of the 2013 Bonds. From time to time Foster Pepper PLLC serves as counsel to the Underwriters on transactions unrelated to the 2013 Bonds.

The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the status of the interest on the 2013 Bonds for federal income tax purposes will be in substantially the form appended hereto in Appendix F—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE 2013 BONDS."

Certain legal matters will be passed upon for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters.

TAX MATTERS

At the closing of the 2013 Bonds, Special Tax Counsel is expected to deliver its opinion, based upon an analysis of existing laws, regulations, rulings, a procedure and methodology, and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, that interest on the 2013 Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code") and Section 9(f) of the Pacific Northwest Power Planning and Conservation Act, Public Law 96-501 (the "Northwest Power Act"). Special Tax Counsel also is expected to deliver its opinion that interest on the 2013 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel is expected to observe that interest on the 2013 Bonds is included in adjusted current earnings when calculating corporate alternative minimum taxable income. In rendering its opinion, Special Tax Counsel will rely on the opinions of Bond Counsel as to the validity of the 2013 Bonds and the due authorization and issuance of the 2013 Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix F—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE 2013 BONDS."

To the extent the issue price of any maturity of the 2013 Bonds is less than the amount to be paid at maturity of such 2013 Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2013 Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the 2013 Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the 2013 Bonds is the first price at which a substantial amount of such maturity of the 2013 Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the 2013 Bonds accrues daily over the term to maturity of such 2013 Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such 2013 Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such 2013 Bonds. Beneficial Owners of the 2013 Bonds should consult their own tax advisors with respect to the

tax consequences of ownership of 2013 Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such 2013 Bonds in the original offering to the public at the first price at which a substantial amount of such 2013 Bonds is sold to the public.

2013 Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The Code and the Northwest Power Act impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the 2013 Bonds. The District and Bonneville have made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the 2013 Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the 2013 Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the 2013 Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring), or any other matters coming to the attention of Special Tax Counsel after the date of issuance of the 2013 Bonds may adversely affect the value of, or the tax status of interest on, the 2013 Bonds. Accordingly, the opinion of Special Tax Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Special Tax Counsel is expected to deliver its opinion that interest on the 2013 Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, the 2013 Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel is expected to express no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the Code or the Northwest Power Act or court decisions may cause interest on the 2013 Bonds to be subject, directly or indirectly, in whole or in part, to federal income taxation, to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. As one example, the Obama Administration's proposed 2014 budget includes a legislative proposal which, for tax years beginning after December 31, 2013, would limit the exclusion from gross income of interest on obligations like the 2013 Bonds to some extent for taxpayers who are individuals and whose income is subject to higher marginal income tax rates. The introduction or enactment of any such legislative proposals or clarification of the Code or the Northwest Power Act or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the 2013 Bonds. Prospective purchasers of the 2013 Bonds should consult their own tax advisors regarding the potential impact of any pending or proposed federal or state tax legislation, regulations or litigation, as to which Special Tax Counsel is expected to express no opinion.

The opinion of Special Tax Counsel is expected to be based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the 2013 Bonds for federal income tax purposes. It is not binding on the Internal Revenue Service ("IRS") or the courts. Furthermore, Special Tax Counsel cannot give and is not expected to give any opinion or assurance about the future activities of the District or Bonneville, or about the effect of future changes in the Code, the Northwest Power Act, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. The District and Bonneville will covenant, however, to comply with the requirements of the Code.

Special Tax Counsel's engagement with respect to the 2013 Bonds will end with the issuance of the 2013 Bonds, and, unless separately engaged, Special Tax Counsel is not obligated to defend the District, Bonneville or the

Beneficial Owners regarding the tax-exempt status of the 2013 Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than the District, Bonneville and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which the District or Bonneville legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the 2013 Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the 2013 Bonds, and may cause the District, Bonneville or the Beneficial Owners to incur significant expense.

RATINGS

Moody's Investors Service ("Moody's") and Fitch Ratings ("Fitch") have assigned the 2013 Bonds the ratings of "Aa1" and "AA," respectively. Ratings were applied for by the District and certain information was supplied by the District and Bonneville to such rating agencies to be considered in evaluating the 2013 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 2013 Bonds. A securities rating is not a recommendation to buy, sell or hold securities.

UNDERWRITING

Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Goldman Sachs & Co. and J.P. Morgan Securities LLC, as underwriters of the 2013 Bonds (the "Underwriters") have jointly and severally agreed, subject to certain conditions, to purchase the 2013 Bonds from the District and to make a bona fide public offering of such 2013 Bonds at not in excess of the public offering prices (or prices corresponding to the yields) set forth on the inside cover page of this Official Statement. The aggregate Underwriters' compensation under the contract of purchase for the 2013 Bonds is $409,201. The Underwriters' obligations are subject to certain conditions precedent contained in the contract of purchase, and they will be obligated to purchase all 2013 Bonds being sold under the contract of purchase if any such 2013 Bonds are purchased.

The 2013 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2013 Bonds into investment trusts) at prices lower than such initial offering prices, and such initial offering prices may be changed from time to time by the Underwriters.

Citigroup Inc., parent company of Citigroup Global Markets Inc., one of the Underwriters, has informed the District and Bonneville that it has entered into a retail brokerage joint venture with Morgan Stanley. As part of the joint venture, Citigroup Global Markets Inc. will distribute municipal securities to retail investors through the financial advisor network of Morgan Stanley Smith Barney LLC. This distribution arrangement became effective on June 1, 2009. As part of this arrangement, Citigroup Global Markets Inc. will compensate Morgan Stanley Smith Barney LLC for its selling efforts with respect to the 2013 Bonds.

Goldman, Sachs & Co. ("Goldman Sachs"), one of the Underwriters, has informed the District and Bonneville that it has entered into a master dealer agreement (the "Master Dealer Agreement") with Incapital LLC ("Incapital") for the distribution of certain municipal securities offerings, including the 2013 Bonds, to Incapital's retail distribution network at the initial public offering prices. Pursuant to the Master Dealer Agreement, Incapital will purchase the 2013 Bonds from Goldman Sachs at the initial public offering price less a negotiated portion of the selling concession applicable to any 2013 Bonds that Incapital sells.

J.P. Morgan Securities LLC ("JPMS"), one of the Underwriters, has informed the District and Bonneville that it 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 2013 Bonds, at the original issue prices. Pursuant to each Dealer Agreement (if applicable to this transaction), each of UBSFS and CS&Co. will purchase the 2013 Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any 2013 Bonds that such firm sells.

The Underwriters have provided the following information to the District for inclusion in this Official Statement. The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Certain of the Underwriters and their respective affiliates have provided, and may in the future provide, a variety of these services to the District and Bonneville and to persons and entities with relationships with the District and Bonneville, for which they received or will receive customary fees and expenses.

In the ordinary course of their various business activities, the Underwriters and their respective affiliates, officers, directors and employees may purchase, sell or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of the District and Bonneville (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with the District and Bonneville. The Underwriters and their respective affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

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

J. Aron & Company, an indirect wholly owned affiliate of Goldman Sachs and Co., is a signatory to the BPA Enabling Agreement (Agreement to Enable Future Purchases, Sales and Exchanges of Power and Other Services) and has transacted with Bonneville thereunder.

Merrill Lynch, Pierce, Fenner & Smith Incorporated (an affiliate of Bank of America, N.A.), Citibank N.A. (an affiliate of Citigroup, Inc.), and J.P. Morgan Chase Bank, N.A. (an affiliate of JPMS), all have extended indirect credit to Bonneville in transactions unrelated to the issuance of the 2013 Bonds.

CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934 ("Rule 15c2-12"), the District and Bonneville will enter into a Continuing Disclosure Agreement, to be dated the date of delivery of the 2013 Bonds, for the benefit of the owners and beneficial owners of the 2013 Bonds, to provide certain financial information and operating data relating to the District (the "District Annual Information"), certain financial information and operating data relating to Bonneville (the "Bonneville Annual Information," and, together with District Annual Information, the "Annual Information") and to provide timely notices of the occurrence of certain enumerated events with respect to the 2013 Bonds. The District Annual Information is to be provided not later than the last day of the ninth month after the end of the District's fiscal year, commencing with the fiscal year ended December 31, 2013. The Bonneville Annual Information is to be provided not later than 180 days after the end of the Federal Columbia River Power System fiscal year, commencing with the fiscal year ended September 30, 2013. The Annual Information and notices of aforesaid enumerated events will be filed by the District with the Municipal Securities Rulemaking Board (the "MSRB"). Currently, the information filed with the MSRB is available to the public without charge through its Electronic Municipal Market Access system ("EMMA").

The District has not failed to comply with all previous undertakings with respect to Rule 15c2-12 in any material respect in the preceding five years. In addition, Bonneville has not failed to comply with all previous undertakings with respect to Rule 15c2-12 in any material respect in the preceding five years; however, Bonneville has not included in its reports an update of the table of Operating Federal System Projects for Operating Year 2013, as provided under certain (but not all) of its previous undertakings. The information in such table does not vary substantially from year to year. On August 8, 2012, Bonneville filed a supplement to its reports for the previous five years to include Operating Federal System Projects tables for Operating Year 2008 through Operating Year 2013. The nature of the information to be provided in the Annual Information and the notices of such material events are set forth in Appendix G—"FORM OF THE CONTINUING DISCLOSURE AGREEMENT."

INITIATIVE AND REFERENDUM

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

MISCELLANEOUS

The references, excerpts and summaries contained herein of the Resolution, the Cowlitz Falls Agreements and any other documents or agreements referred to herein do not purport to be complete statements of the provisions of such documents or agreements, and reference should be made to such documents or agreements for a full and complete statement of all matters relating to the 2013 Bonds, the basic agreements securing the 2013 Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Resolution, the Cowlitz Falls Agreements and other reports, documents, agreements and studies referred to herein and in the Appendices hereto are available upon request at the office of the District in Chehalis, Washington.

The authorizations, agreements and covenants of the District are set forth in the Resolution, and neither this Official Statement nor any advertisement of any of the 2013 Bonds is to be construed as a contract with the holders of the 2013 Bonds. Any statements made in this Official Statement involving matters of opinion or estimates, whether or not expressly so identified, are intended merely as such and not as representations of fact.

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

TABLE OF CONTENTS

	PAGE
GENERAL	A-1
FISCAL YEARS 2012-2028 REGIONAL POWER SALES BACKGROUND	A-3
Power Sales to Preference Customers	A-3
Other Regional Power Sales	A-4
CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE	A-4
Loads and Resources Expectations	A-4
Current Bonneville Power and Transmission Rates	A-5
Bonneville's Power and Transmission Rates Proposal for the Fiscal Year 2014-2015 Rate Period	A-5
2013 Prepaid Power Program	A-7
Fiscal Year 2012 Financial Results	A-7
Fiscal Year 2013 Expectations	A-7
Federal Sequestration for Fiscal Year 2013 and Effects on Bonneville	A-8
Bonneville Power Administrator, William K. Drummond	A-8
POWER SERVICES	A-8
Description of the Generation Resources of the Federal System	A-9
Bonneville's Power Trading Floor Activities	A-12
Regional Customers and Other Power Contract Parties of Bonneville's Power Services	A-13
Certain Statutes and Other Matters Affecting Bonneville's Power Services	A-17
TRANSMISSION SERVICES	A-30
Bonneville's Federal Transmission System	A-31
FERC and Non-discriminatory Transmission Access and Separation of Power Services and Transmission Services	A-32
Bonneville's Transmission and Ancillary Services Rates	A-34
Initial Proposed Rates for Transmission and Ancillary Services for the 2014-2015 Rate Period	A-34
Bonneville's Participation in a Regional Transmission/Planning Organization	A-35
MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES	A-36
Bonneville Ratemaking and Rates	A-36
Limitations on Suits against Bonneville	A-37
Laws Relating to Environmental Protection	A-37
Energy Policy Act of 2005	A-37
2010 Dodd-Frank Act and Bonneville	A-38
Other Applicable Laws	A-39
Columbia River Treaty	A-39
Proposals for Federal Legislation and Administrative Action Relating to Bonneville	A-39
Climate Change	A-40
Preparedness and Cyber Security	A-40
Wind Generation Development and Integration into the Federal Transmission System	A-41
Columbia Generating Station and Energy Northwest's Purchase of Uranium	A-43
BONNEVILLE FINANCIAL OPERATIONS	A-43
The Bonneville Fund	A-43
The Federal System Investment	A-44
Bonneville Borrowing Authority	A-44
Banking Relationship between the United States Treasury and Bonneville	A-45
Bonneville's Capital Program	A-45
Energy Northwest Net Billing Agreements	A-46
Energy Northwest Direct Pay Agreements	A-47
Direct Funding of Federal System Operations and Maintenance Expense	A-48
Order in Which Bonneville's Costs Are Met	A-48
Position Management and Derivative Instrument Activities and Policies	A-50
Historical Federal System Financial Data	A-50
Management Discussion of Operating Results	A-53
Statement of Non-Federal Project Debt Service Coverage	A-55
Management Discussion of Unaudited Results for the Six Months Ended March 31, 2013	A-57
BONNEVILLE LITIGATION	A-58
Columbia River ESA Litigation	A-58
DSI Service Litigation	A-59
Tiered Rates Methodology Record of Decision	A-59
Certain Statutes and Other Matters Affecting Bonneville's Power Services	A-59
2010 and 2012 Power Rates Challenge	A-60
Residential Exchange Program Litigation	A-60
Southern California Edison v. Bonneville Power Administration	A-61
Rates Litigation Generally	A-62
Lease-Purchase Program Property Taxes	A-62
Miscellaneous Litigation	A-62

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Public Utility District No. 1 of Lewis County, Washington (the "District" or, the "Issuer") by Bonneville for use in the Official Statement dated June 13, 2013, furnished by the Issuer (the "Official Statement") with respect to Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 (the "2013 Bonds"). The Cowlitz Falls Hydroelectric Project (the "Cowlitz Falls Project") is described in the Official Statement under "THE COWLITZ FALLS PROJECT." In 1991, the United States of America, Department of Energy ("DOE"), acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), entered into a Power Purchase Contract with the Issuer under which Bonneville has agreed to acquire all of the electric power from the Cowlitz Falls Project through June 30, 2032 (the "Power Purchase Contract") and has agreed to pay an amount equal to Project Power Costs, as defined in the Power Purchase Contract, whether or not the Cowlitz Falls Project is terminated, operating or operable. Debt service on the 2013 Bonds is a Project Power Cost. See the Official Statement under "SECURITY FOR THE 2013 BONDS," "SECURITY FOR THE 2013 BONDS—Power Purchase Contract," and Appendix E to the Official Statement under "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT."

In 1991, Bonneville also entered into a Payment Agreement under which Bonneville will have the obligation to make payments with respect to debt service on the 2013 Bonds, when, as and if issued, if Bonneville does not make such payments under the Power Purchase Contract. See the Official Statement under "SECURITY FOR THE 2013 BONDS—Payment Agreement" and Appendix E to the Official Statement under "SUMMARY OF THE POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT." The Power Purchase Contract and the Payment Agreement are referred to in this Appendix A, collectively, as the "Cowlitz Falls Project Agreements."

The information in this Appendix A is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the 2013 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 DOE. Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following Federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 Federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-Federally-owned and -operated projects, including the Cowlitz Falls Project and the Columbia Generating Station, an operating nuclear generating station with a rated capacity of approximately 1,150 megawatts owned by Energy Northwest, which is a joint operating agency of the State of Washington. In addition, firm energy from transfers, exchanges, and purchases comprise the remaining portion of Bonneville's electric power resources. Not taking into account estimated power lost through the transmission of electricity from generation sites to load sites ("line losses"), Bonneville estimates that the foregoing projects and contracts have an expected aggregate energy output in the current Operating Year 2013 of approximately 10,585 annual average megawatts (defined below) under median water conditions and approximately 8,586 annual average megawatts under low water conditions. (Bonneville's "Operating Year" runs from August 1 through July 31. By contrast, its "Fiscal Year" runs from October 1 through September 30.) (Annual average megawatts are the number of megawatt-hours of electric energy used, transmitted, or produced over the course of one year and each annual average megawatt is equal to 8,760 megawatt-hours.)

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

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

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

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

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

Bonneville 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 $886 million (including $53 million in principal payments in advance of due dates) in full and on time for Bonneville's fiscal year ended September 30, 2012 ("Fiscal Year 2012"). Bonneville has made all payments to the United States Treasury in full and on time since 1984.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including its payments under the Cowlitz Falls Project Agreements, and other operating and maintenance

expenses have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash payments under the Cowlitz Falls Project Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading "SECURITY FOR THE 2013 BONDS" and see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

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

FISCAL YEARS 2012-2028 REGIONAL POWER SALES BACKGROUND

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 providing 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." Proportionately, Preference Customers are the largest customer group to whom Bonneville sells power. For example, for Operating Year 2013, Bonneville estimated on a planning basis that it would meet 8,436 annual average megawatts of loads, of which approximately 83 percent is Preference Customer loads, approximately five percent is Federal agency and DSI loads, and approximately twelve percent is exports and other intra-Regional contract obligations. (Actual sales of electric power in Operating Year 2013 will be available after it ends. Actual energy amounts may differ from planned amounts because of energy usage variations due to the weather, end-user behavior, economic activity and other factors.) (The term "annual average megawatts" is defined on Page A-1 of this Appendix A).

Power Sales to Preference Customers

In Fiscal Year 2012, Bonneville's power service to its Preference Customers commenced 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 approximately 26.9 percent of Federal System generation.

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.

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 approximately equal to the generating output of the Federal System in Operating Year 2011. Tier 1 PF Rates 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, is and 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 that purchase power from Bonneville to meet

Tier 2 Loads, such purchases are integrated with purchases of power for Tier 1 Loads into a single power purchase. The purchase of power from Bonneville for Tier 2 Loads is made on a take-or-pay basis for the specified amount of power.

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 Cowlitz Falls Project and the Columbia Generating Station, together with certain terminated nuclear generating stations the costs of which Bonneville has contracted to meet (the "Net Billed Projects"), 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 actual seasonal surplus (secondary) energy derived from Tier 1 Federal System resources in a proportionate share equal to their Slice percentages, 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 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. At the end of Fiscal Year 2012, certain Preference Customers committed to place 75 and 18 annual average megawatts in aggregate Tier 2 Loads on Bonneville in Fiscal Years 2014 and 2015, respectively.

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."

Other Regional Power Sales

Bonneville is authorized to sell power to DSIs, but has no statutory obligation to do so. Bonneville currently has separate power sales agreements in effect with two DSIs through calendar year 2022. One sale provides for Bonneville to deliver 300 annual average megawatts to Alcoa, Inc. ("Alcoa"), an aluminum industry DSI. The other provides for Bonneville to sell approximately 20 annual average megawatts to Port Townsend Paper Corporation ("Port Townsend"), a non-aluminum industry DSI. No court challenges to these contacts have been made and the time within which to challenge these contracts in court has elapsed.

Bonneville's prior service to DSIs is and has been the subject of litigation. The DSI litigation is before 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. See "BONNEVILLE LITIGATION—DSI Service Litigation."

Bonneville also sells Full Requirements power to eight Federal agencies to meet their loads, which Bonneville estimates will be approximately 119 annual average megawatts in Operating Year 2013. These sales are made at the PF Preference Rate for full requirements.

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."

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Loads and Resources Expectations

Bonneville expects that, in aggregate, its total power sales obligations will ultimately equate to approximately 8,216 annual average megawatts in Operating Year 2014 and will be approximately 8,222 annual average megawatts in Operating Year 2015. Of these loads: (i) the aggregate of Preference Customer, Federal agency, and DSI loads are forecast to increase from 7,506 annual average megawatts in Operating Year 2014 to 7,563 annual average megawatts in Operating Year 2015, and (ii) other Bonneville exports and intra-Regional contract obligations are forecast to decrease from approximately 710 annual average megawatts in Operating Year 2014 to 659 annual average megawatts in Operating Year 2015. By contrast, Bonneville estimates that the Federal System resources together with contract

purchases and similar agreements will provide, under certain assumptions of historically low water conditions, approximately 8,227 annual average megawatts in Operating Year 2014, decreasing to 7,937 annual average megawatts in Operating Year 2015. (These estimates take into account power purchase and generating resource production, and reductions for "line losses," that is, energy losses from transmitting power from generation sources to loads of 239 annual average megawatts in Operating Year 2014 and 230 annual average megawatts in Operating Year 2015.) Bonneville believes, given the amount of generating resources of the Federal System, that it will have a minimal firm energy surplus in Operating Year 2014. See also "POWER SERVICES—Description of the Generation Resources of the Federal System" and the table entitled "Operating Federal System Projects for Operating Year 2013." (The term annual average megawatts is defined on page A-1 of this Appendix A.)

To meet its load growth obligations, Bonneville does not believe that it will need to acquire substantial new, long-term resources apart from electric power 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 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. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program."

Current Bonneville Power and Transmission Rates

Bonneville has established power and transmission rates for Fiscal Years 2012 and 2013 (the "2012-2013 Rate Period"), and FERC granted final approval of such rates (the "Final 2012-2013 Rates") in December 2012. The Final 2012-2013 Rates include the first power rates that implement the Tiered Rates Methodology. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fiscal Year 2012-2013 Power Rates," and "TRANSMISSION SERVICES—Transmission Rates." Certain industrial end-use customer groups and one Preference Customer have challenged certain features of the power rates portion of the Final 2012-2013 Rates. The challenge relates to the amount of future industrial load growth for which Preference Customers may purchase power from Bonneville at Tier 1 PF Rates. See "BONNEVILLE LITIGATION—Final 2012-2013 Power Rates Challenge."

Bonneville's Power and Transmission Rates Proposal for the Fiscal Year 2014-2015 Rate Period

In November 2012, Bonneville released an initial proposal for power and transmission rates for the 2014-2015 Rate Period (the "Initial Proposal"). Bonneville is consolidating both its power rates and transmission general rates proposals into a single proceeding. Subsequent to the issuance of the Initial Proposal, Bonneville initiated an administrative hearings process for establishing final proposed power and transmission rates (the "Final 2014-2015 Rate Proposal"). Prior to August 1, 2013, Bonneville will submit the Final 2014-2015 Rate Proposal, together with a record of decision, to FERC for its review. The Final 2014-2015 Rate Proposal may differ from the Initial Proposal.

Consistent with longstanding policy, Bonneville's proposed power and transmission rates in the Initial Proposal were prepared with the goal of assuring at least a 95 percent probability over the two-year rate period that Bonneville will make its scheduled payments to the United States Treasury on time and in full ("Treasury Payment Probability"). 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 Cowlitz Falls Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met." In general, the Initial Proposal proposes increases in both power and transmission rates when compared to rates now in effect. Upward rate pressures that are reflected in the Initial Proposal arise from increased costs generally.

Initial Proposed Rates for Power

Under the Initial Proposal, Bonneville has proposed on a preliminary basis that PF Preference Rates increase by 9.6 percent, in aggregate, over current rate levels. After taking into account the different treatment of seasonal surplus (secondary) power between Slice and non-Slice power sales, the Initial Proposal would average a nine percent increase for non-Slice power products sold to Preference Customers while Slice rate levels would increase by ten percent, once the expected value of the Slice share of Federal System seasonal surplus (secondary) energy is factored into the Slice rate. The rate levels for Full Requirements power product would increase from $29.72 per megawatt hour on average under current rates to $32.41 under the Initial Proposal and the rates for Slice would increase from $1.952 million per month per percentage point of Slice under current rates to $1.967 million per month per percentage point of Slice under the Initial Proposal. Once the value of the portion of Slice from seasonal surplus (secondary) energy is taken into account, the Slice rate, expressed per megawatt hour of Slice firm sales, would increase from $26.52 to $29.23 per megawatt hour. With respect to partial and full requirements power rate levels and rates levels for the Block portion of Slice/Block, market price forecasts for Bonneville's seasonal surplus (secondary) power sales continue to show some suppression, primarily from the electric power market price effects arising from low natural gas prices. Expected

seasonal surplus (secondary) energy revenues are applied as a credit against expected costs in determining PF Preference Rate levels, other than Slice rate levels. Bonneville will use updated cost and revenue forecasts and other updated information in preparing the Final 2014-2015 Rate Proposal.

Under the Initial Proposal, rate levels for Tier 2 purchases would be lower than current rate period levels, decreasing on average from $48.11 per megawatt hour to $39.04 per megawatt hour. The Initial Proposal forecasts that Tier 2 rates will be applicable to approximately 75 and 18 annual average megawatts of Tier 2 Loads in aggregate in Fiscal Years 2014 and 2015, respectively.

Under the Initial Proposal, the average IP Rate, which is applicable to firm power sales to DSIs, would increase to $38.99 per megawatt hour, an increase of 7.4 percent over the comparable rate levels in the current rate period. The Initial Proposal forecasts that DSI loads will be 312 annual average megawatts in the 2014-2015 Rate Period. (Bonneville has entered into power sales contracts to deliver approximately 320 annual average megawatts to the DSIs in the rate period; however, for ratemaking purposes Bonneville has assumed that a DSI will exercise certain rights to meet a portion of its loads by indirect purchases from Bonneville through a Preference Customer).

Consistent with current and prior power rates, the Initial Proposal includes a power 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. The CRAC would enable Bonneville to obtain up to an additional $300 million in additional power rate revenues in the applicable fiscal year, depending on a variety of factors. Based on Fiscal Year 2013 second quarter results and estimates and forecasts of numerous factors including possible power prices for and the amounts of secondary energy sales in the current fiscal year, Bonneville estimates there is very little chance that the CRAC will trigger for Fiscal Year 2014 rates.

For more detail on the risk mitigation tools for the power rates portion of the Initial Proposal see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Risk Mitigation Tools Underlying the Initial Proposed Power Rates for the Fiscal Year 2014-2015 Rate Period."

Initial Proposed Rates for Transmission and Ancillary Services

Bonneville is proposing, on a preliminary basis, to increase its transmission rates approximately 13 percent, mainly due to continued efforts to maintain Federal Transmission System reliability and meet increasing demands for transmission in the Pacific Northwest. If adopted, the proposal would be Bonneville's first transmission rate increase in eight years.

A number of factors are leading to increased spending and the proposed transmission rates. Construction of new lines and replacements to maintain reliability and facilitate the integration of renewable resources, such as wind, accounts for slightly more than one half of the proposed transmission rate increase. Increased mandatory compliance requirements and additional cyber and physical security requirements and other operational and maintenance expenses account for approximately one half of the proposed transmission rate increase.

Under a settlement agreement of certain matters in the transmission rate proceeding, Bonneville's rate to balance renewable resources, primarily wind generation, will be $1.20 per megawatt of installed wind generation capacity, which is comparable to the current rate of $1.23 per megawatt of installed wind generation capacity. Bonneville's rate is intended to have built-in flexibility to recover any additional costs that may be needed to keep the system reliable as new wind generation resources served by Transmission Services are added. Bonneville holds a portion of the Federal System hydroelectric system in reserve to increase and decrease on short notice to accommodate fluctuating generation by wind and other renewable resources as their production varies. These reserves ensure that the amount of power being produced matches the amount being consumed across the system to maintain system operation and reliability.

For more detail on the transmission and ancillary services portion of the Initial Proposal, see "TRANSMISSION SERVICES—Initial Proposed Rates for Transmission and Ancillary Services for the 2014-2015 Rate Period."

Bonneville has also proposed on a preliminary basis a supplemental rate for the occasional seasonal oversupply of electricity that arises from periodic, large concentrations of renewable generation (primarily wind generation) and hydroelectric generation. In such a situation, Bonneville may displace renewable generation with Federal System hydroelectric power to assure that hydroelectric power generation can continue to operate in order to protect fish species. In these circumstances, Bonneville displaces the renewable electric generation in its transmission balancing authority with Federal System hydroelectric power, and provides compensation to such renewable generators for certain costs relating to displacing their generation. Under the over-supply transmission rate proposal, the cost of displacement (primarily, the amount of compensation provided to the displaced generators) will be allocated entirely to users of the Federal Transmission System proportionate to their use at the time of the displacement. These transmission users include Bonneville Power Services, Preference Customers, the renewable generators (primarily wind generators), DSIs, Regional IOUs and entities that wheel electricity through the Region on the Federal Transmission System.

Oversupply costs in Fiscal Year 2012 were approximately $2.7 million and could be $50 million in a year with conditions of high springtime stream flows, high wind generation, and low demand. This "oversupply" rate proceeding is occurring in connection with the proceeding for Bonneville's wholesale power rates and transmission and ancillary services rates. See "TRANSMISSION SERVICES—Over-Supply Rate Proposal" and "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Over-generation from High Water and High Wind."

2013 Prepaid Power Program

Bonneville and each of four Preference Customers have agreed to separate electricity prepayment arrangements in which the Preference Customers have provided lump sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028, the termination date of the Long-Term Preference Contracts. The participating Preference Customers are 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 is and will be represented by fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville has received $340 million in aggregate of prepayments from the participating customers. The offsetting prepayment credits are set at $2.55 million per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028.

The 2013 Prepaid Power Program involved determining the amount of the prepayments and the amount of resulting credits through a competitive process in which Preference Customers submitted bids (offers) to participate in the program. The program was sequenced so that Bonneville would know the prepayment amounts and credits in establishing power rates for the 2014-2015 Rate Period. Bonneville expects to expend the amounts it received through the 2013 Prepaid Power Program by the end of Fiscal Year 2015. Depending on a variety of factors it is possible that Bonneville may seek to implement a power prepayment program in connection with future power rate proposals. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Fiscal Year 2012 Financial Results

In Fiscal Year 2012, Bonneville made its scheduled United States Treasury payments on time and in full for the 29th consecutive year. Bonneville finished Fiscal Year 2012 with financial reserves of $1.02 billion, which is a decline of approximately nine percent from the prior fiscal year. Bonneville's net revenues increased $5 million from net revenues of $82 million in Fiscal Year 2011 to net revenues of $87 million in Fiscal Year 2012, based primarily on increased net revenues from Transmission Services operations, which were approximately $89 million in Fiscal Year 2012. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2012."

Fiscal Year 2013 Expectations

Analyses as of June 7, 2013, prepared by the Northwest River Forecast Center and relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2013 water supply for the Columbia River basin, will be approximately 93 percent of the 30-year historical average, as measured in terms of millions of acre feet of water (or "MAF") runoff at The Dalles Dam. Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and British Columbia.

In Fiscal Year 2013, Bonneville commenced utilizing and reporting a new financial metric, "Adjusted Net Revenues." While Adjusted Net Revenues is not a measure in accordance with Generally Accepted Accounting Principles, Bonneville management believes the use and reporting of Adjusted Net Revenues assists in reflecting Bonneville's financial performance for day-to day operations in applicable fiscal years. Adjusted Net Revenues is net revenue after removing the effects of certain debt management actions from prior fiscal years. These debt management actions were implemented to replenish available United States Treasury borrowing capacity by extending into the future the repayment dates of debt for Energy Northwest's Net Billed Projects. The resulting reductions in intervening debt payments (in the period between the dates the Energy Northwest debt was initially due to be repaid and the dates that that refinanced debt was re-set to be repaid) resulted in funds becoming available to pay down the aggregate principal amount of Bonneville's then-outstanding United States Treasury debt. This prior program is referred to as Debt Optimization. Under Generally Accepted Accounting Principles, Energy Northwest debt expense is recorded when the debt is repaid. With a lower Energy Northwest debt expense due to the debt management actions, Debt Optimization resulted in higher net revenues than otherwise would have been reported in the affected fiscal years absent the debt management actions. As the Energy Northwest debt that was issued for the refinancing under Debt Optimization reaches maturity, as is now occurring, the converse of the original effects of Debt Optimization on financial reporting is also occurring: nonfederal projects' expense is higher than, and Federal System net revenues are lower than, would have been the case without Debt Optimization. The effects of these past debt management actions are not considered to

be related to ongoing Federal System operations, and therefore management has determined that Adjusted Net Revenues is a better representation of Federal System financial performance for the period.

Based on information as of the March 31, 2013, Bonneville forecasts that Adjusted Net Revenues will be $21 million in Fiscal Year 2013. In establishing the Final 2012-2013 Rates, Bonneville forecasted that for Fiscal Year 2013, Adjusted Net Revenues would be $27 million. More particularly, based on information as of March 31, 2013, Bonneville forecasts that Power Services' net revenue will be negative $51 million in Fiscal Year 2013. By contrast, in establishing the Final 2012-2013 Rates, Bonneville forecasted that for Fiscal Year 2013, Power Services' net revenue would be negative $2 million. Below average availability of seasonal surplus (secondary) energy for sale from Federal System hydroelectric generation (resulting from below average precipitation) and low market prices resulting from low prices for natural gas have contributed to Bonneville's Fiscal Year 2013 Adjusted Net Revenues forecast.

As of March 31, 2013, Bonneville estimated that financial reserves will be approximately $1.23 billion at the end of Fiscal Year 2013 as compared to $1.02 billion as of the end of Fiscal Year 2012. 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 Adjusted 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 2013 and more recent internal updates, Bonneville believes that it will meet its Fiscal Year 2013 United States Treasury payment responsibilities on time and in full. Such belief is based on information and conditions in Bonneville's current fiscal year, which are subject to change.

Federal Sequestration for Fiscal Year 2013 and Effects on Bonneville

Bonneville is a Federal agency and is subject to applicable Federal budget laws. In Fiscal Year 2012, Congress enacted a budget law (the "2012 Budget Law"), which, when applied together with provisions of pre-existing Federal budget law, has resulted in across the board reductions in Fiscal Year 2013 budgetary resources for many Federal programs, projects, and activities, with the consequence that the authority to incur obligations and make expenditures in Fiscal Year 2013 with respect to the affected Federal programs, projects and activities has been similarly reduced. The sequestration is a temporary reduction in expenditure authority for Fiscal Year 2013 only. Congress could enact additional legislation to ameliorate its effects.

Under longstanding Federal budget law and Federal budget law practice, Bonneville's operations have been exempt from sequestration; however, one effect of the Office of Management and Budget's application of the 2012 Budget Law is to subject certain of Bonneville's administrative costs to sequestration in Fiscal Year 2013. Bonneville estimates that if the sequestration were to remain in effect for the remainder of Fiscal Year 2013 it would result in a reduction of Bonneville's administrative costs in the amount of approximately $6 million, when compared to the amounts previously projected in the Federal budget for Fiscal Year 2013. The sequestration does not and will not adversely affect the operation of the Federal System or Bonneville's authority or ability to meet its existing contractual obligations, including payments with respect to debt service on the 2013 Bonds under the Cowlitz Falls Project Agreements. Bonneville is unable to predict whether Congress will enact legislation leading to sequestration in future fiscal years.

Bonneville Power Administrator, William K. Drummond

On February 7, 2013 William K. Drummond was sworn in as Bonneville's Administrator. Mr. Drummond had served as Bonneville's Deputy Administrator since October 2011. Prior to joining Bonneville, Mr. Drummond was manager of the Western Montana Electric Generating and Transmission Cooperative in Missoula, Montana for 17 years. From 1988 to 1994 Mr. Drummond led the Public Power Council, an association of Preference Customers. Mr. Drummond has served on various Regional task forces and committees, including the Northwest Energy Efficiency Alliance, the Northwest Wind Integration Forum, and Northwest Energy Efficiency Task Force. He has also served on committees of the American Public Power Association and the National Rural Electric Cooperative Association. Mr. Drummond has degrees in forestry from the University of Montana and economics from the University of Arizona.

POWER SERVICES

Bonneville's Power Services is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. Power Services was responsible for approximately $2.5 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 76 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 2012.

Description of the Generation Resources of the Federal System

Generation

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

Bonneville defines "firm power" as electric power that is continuously available from the Federal System during adverse water conditions to meet Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on assumptions related to a low-water period on record for the Columbia River basin referred to as "Critical Water." Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity (measured in megawatts) and firm energy (measured in annual average megawatts). Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2014 (August 1, 2013 through July 31, 2014), the total Federal System would be capable of producing approximately 8,468 annual average megawatts of firm energy under low water conditions and not accounting for line losses. This generation includes approximately 6,879 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,152 annual average megawatts from Columbia Generating Station and other non-Federally-owned resources (including co-generation, renewable, and non-utility generation projects), and approximately 437 annual average megawatts of firm energy from power purchases, exchanges, and other non-Federal transactions. See the table entitled "Operating Federal System Projects for Operating Year 2014."

Federal Hydro-Generation

The share of hydropower from Federally-owned hydroelectric projects and a small amount of power Bonneville has acquired from non-Federally-owned hydroelectric projects for Operating Year 2014 is estimated to be approximately 82 percent of Bonneville's total firm power supply. Bonneville's large resource base of hydropower results in operating and planning characteristics that differ from those of major utilities that lack a substantial hydropower base. See the table entitled "Operating Federal System Projects for Operating Year 2014."

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

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

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 2014, the Federal System is estimated to generate seasonal surplus (secondary) energy of 1,516 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 2,765 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 9 in the following table "Operating Federal System Projects for Operating Year 2014." In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. Bonneville projects that it will continue to have long-term contracts for power purchases, exchanges, and other non-Federal transactions that provide approximately 437 annual average megawatts.

Operating Federal System Projects for Operating Year 2014

In all years, the energy generating capability of the Federal System's hydroelectric projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, stream-flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes an 80-year record of river flows based on the period from 1929-2008 for planning purposes. During this period, low water conditions ("Low Water Flows") occurred in 1936-37, 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 2014, the Federal System January 120-Hour peaking capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows (referred to as "Firm Energy"), Median Water Flows (referred to as "Median Energy"), and High Water Flows (referred to as "Maximum Energy"). The same forecasting procedures are also used for non-Federally-owned hydroelectric projects. Thermal projects, the output of which does not vary with river flow conditions, are estimated using current generating capacity, plant capacity factors, and maintenance schedules.

Operating Federal System Projects for Operating Year 2014[1]

Project	Initial Year in Service	No. of Generating Units	January Capacity (120-Hour Peak MW)(2)	Maximum Energy (aMW)(3)	Median Energy (aMW)(4)	Firm Energy (aMW)(5)
United States Bureau of Reclamation (Reclamation) Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	5,340	2,611	2,383	1,988
Hungry Horse	1952	4	319	140	97	76
Other Reclamation Projects(6)		16	32	170	150	120
1. Total Reclamation Projects		53	5,691	2,921	2,630	2,184
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,408	1,496	1,337	1,142
John Day	1968	16	2,295	1,428	1,100	817
The Dalles w/o Fishway(7)	1957	24	1,830	1,042	823	610
Bonneville	1938	20	921	579	558	404
McNary	1953	14	1,036	705	641	486
Lower Granite	1975	6	737	417	297	174
Lower Monumental	1969	6	810	469	318	182
Little Goose	1970	6	859	427	295	178
Ice Harbor	1961	6	586	385	280	157
Libby	1975	5	483	276	224	181
Dworshak	1974	3	434	291	217	145
Other Corps Projects(8)		20	206	284	261	217
2. Total Corps Projects		153	12,605	7,799	6,351	4,695
3. Idle Federal Capacity(9)			(8,376)	0	0	0
4. Total Reclamation and Corps Projects (line 1 + line 2 + line 3)		**206**	**9,921**	**10,720**	**8,981**	**6,879**
Non-Federally-Owned Projects						
Columbia Generating Station(10)	1984	1	1,130	1,030	1,030	1,030
Other Non-Federal Hydro Projects(11)		7	32	60	44	40
Other Non-Federal Projects(12)		11	29	82	82	82
5. Total Non-Federally-Owned Projects		**19**	**1,191**	**1,172**	**1,156**	**1,152**
Federal Contract Purchases						
6. Total Bonneville Contract Purchases (13)		**n/a**	**875**	**456**	**447**	**437**
Total Federal System Resources						
7. Total Federal System Resources (line 4 + line 5 + line 6)		**225**	**11,986**	**12,348**	**10,584**	**8,468**

Source: 2012 Pacific Northwest Loads and Resources Study, Bonneville, October 2012.

(1) Operating Year 2014 is August 1, 2013 through July 31, 2014. Discrepancies from the figures portrayed in the "2012 Pacific Northwest Loads and Resources Study" are due to rounding.

(2) January Capacity is megawatts of capacity ("MW") and is measured by Bonneville as "January 120-Hour Capacity," which is the maximum generation to be produced under Low Water Flows in 20 six hour periods (five days a week, for four weeks) assuming a base case of high loads as experienced historically in the month of January. January is a benchmark month for the Federal System peaking capacity because of the potential for high peak loads during January due to cold winter weather. These January estimates are further reduced by Bonneville for estimated hydro maintenance and estimates of idle Federal System hydro capacity. See footnotes (3) and (9), below.

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

defined on page A-1 of this Appendix A.) 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 annual average megawatts (aMW).

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

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

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

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

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

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station will provide approximately 878 annual average megawatts in most refueling years, as is the case in Operating Year 2013, and 1,030 annual average megawatts in non-refueling years, as is scheduled to occur in Operating Year 2014. Actual generation during an Operating Year will depend on performance of the project. This amount does not take into account any reductions in generation requested by Bonneville related to oversupply events. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development and Integration into the Federal Transmission System—Over-generation from High Water and High Wind."

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

(12) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's Wauna Cogeneration Project (1996), the State of Idaho DWR's Clearwater Hydro (1998), Dworshak Small Hydro (2000), and Rocky Brook Hydro (1999) projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), and Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project, Condon Wind Project, LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 (2001) wind project, a share from NWW Wind Power's Klondike Phase III (2007), the output from the White Bluffs solar project (2002), and a share of the City of Ashland's solar project.

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

Bonneville's Power Trading Floor Activities

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

Based on these studies and specific marketing guidelines, Bonneville actively manages short-term surpluses and deficits through real-time, within-month, and forward sales and purchases, and physical power options.

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

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

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

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

Preference Customers

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

Direct Service Industrial Customers

Bonneville may, but is not required to, sell power to a limited number of DSIs within the Region for their direct consumption. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. Most of the aluminum industry in the Pacific Northwest has ceased to operate. Currently, Bonneville sells power to two DSIs in the aggregate amount of approximately 320 annual average megawatts.

Regional Investor-Owned Utilities

As required by the Northwest Power Act, Bonneville has offered, and four of the six Regional IOUs have agreed to, contracts under which Bonneville could serve Regional IOUs with electric power for their net requirements (meaning a Regional IOU's loads in the Region that are not met by the Regional IOU with its own designated power supplies) beginning in Fiscal Year 2020 if such service is requested not later than the end of Fiscal Year 2016. At the end of Fiscal Year 2016, the Regional IOUs will elect whether or not to purchase requirements power for Fiscal Years 2020 through 2028. Any requirements power provided by Bonneville under these contracts would be priced at the "New Resources Rate." This rate would in effect reflect the marginal cost to Bonneville of acquiring power to meet the loads plus certain other costs. Bonneville believes that it is unlikely, unless circumstances change, that Regional IOUs will place substantial loads, if any, on Bonneville under the Regional IOU long-term requirements contracts because (i) there is no reason to expect that Bonneville's cost to meet such loads, as reflected in the New Resources Rate, would be

significantly lower than the Regional IOUs' cost to meet such loads, (ii) the Regional IOUs are financially motivated to make investments in new generating facilities in order to obtain shareholder returns, (iii) most of the Regional IOUs have state-mandated renewable resource purchase obligations and would have to be assured that such obligations are addressed in any power purchases from Bonneville, (iv) the Regional IOUs would not be able to control directly the terms and costs of the new resources Bonneville would obtain to meet the loads, and (v) the New Resources Rate bears additional costs of statutory rate protection afforded to Preference Customers, thereby likely making the rate uneconomic compared to market alternatives.

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

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

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

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

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

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

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

Credit Risk

Credit risk may be concentrated to the extent that one or more groups of counterparties, including purchasers and sellers, in power transactions with Bonneville have similar economic, industry, or other characteristics that would cause

their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. Credit risk includes not only the risk that counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to the circumstances that relate to other market participants that have a direct or indirect relationship with such a counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. 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 to address, under the Federal Power Act ("FPA"), whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. The foregoing proceedings and the problems experienced in West Coast power markets in 1999-2001 have also engendered litigation affecting Bonneville.

FERC California Refund Docket and California Breach Claims. In the "FERC California Refund Docket," FERC is examining whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC is examining whether and the extent to which power prices were "unjust and unreasonable." The California Power Exchange ("Cal-PX") (which filed for bankruptcy protection and has ceased operations) and the California Independent System Operator ("Cal-ISO") operated centralized market-clearing price auction energy markets where buyers could purchase power. Under a market-clearing auction, power sellers' bids are accepted from lowest to highest price until all power demand is met, and accepted bids are all paid the same price as the bid for the last unit of electricity needed to meet total demand (the highest price that 'clears the market'). The Cal-ISO also entered into non-market-clearing power purchases and exchanges to obtain electric power to meet loads.

Under the competitive power market structure that California established, Bonneville sold power to the Cal-ISO and the Cal-PX in 2000 and 2001. The California investor-owned utilities, which were obligated by law to purchase from the Cal-ISO and Cal-PX markets, later sought refunds for their purchases at FERC. In litigation arising out of the FERC California Refund Docket, the Ninth Circuit Court ultimately held, in September 2005, that Bonneville was not (under law in effect at the time) subject to FERC authority to order refunds. As a result of the court's ruling, the FERC California Refund Docket cannot result in any FERC-ordered refund liability for Bonneville. Notwithstanding the foregoing ruling by the Ninth Circuit Court, Bonneville remains a party to the FERC California Refund Docket, as described below.

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

In light of the foregoing Ninth Circuit Court ruling in connection with the FERC California Refund Docket, the California Attorney General on behalf of California Energy Scheduling Resources, which is a California state agency, and three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric, and Southern California Edison ("SCE")), (the foregoing four parties are referred to collectively herein as the "California Parties"), filed separate breach of contract claims against Bonneville in the United States Court of Federal Claims ("Court of Federal Claims") in March 2007. Each claim seeks unspecified damages related to Bonneville's power sales and related transactions into the Cal-PX and Cal-ISO markets. These claims are referred to herein as the "California Breach Claims." The California Parties also seek to recover pre-judgment and post-judgment interest and litigation costs in the California Breach Claims litigation. Bonneville estimates that the aggregate contract damages claimed by California Parties are $53 million in specified damages plus an additional amount of unspecified damages that could be realized through declaratory orders sought by the California Parties.

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

prices, as established by FERC in separate refund proceedings in the FERC California Refund Docket. The court may conduct a hearing on the actual damages in the summer of 2013.

In the California Breach Claims litigation, the California Parties filed motions seeking certain declaratory relief with regard to: (i) power sales from May 1, 2000 through October 1, 2000 by Bonneville into "Day Ahead" market-clearing price power markets operated by the Cal-ISO and the Cal-PX ("Summer 2000 Transactions"); and (ii) non-market clearing (bi-lateral), multi-day power sales and power exchange transactions by Bonneville into the Cal-ISO's "Exchange and Multi-day" markets in 2000 and 2001 ("Exchange and Multi-day Transactions"). In an order issued in April 2013 (the "April 2013 Order"), the Court of Federal Claims determined that if and when FERC resets prices for the Summer 2000 Transactions and/or the Exchange and Multi-day Transactions, Bonneville will be contractually bound to refund the value that it received in excess of the mitigated prices.

In September 2012, the Ninth Circuit Court, in further review of the FERC California Refund Docket, issued an opinion holding that FERC, in establishing mitigated prices in the Cal-PX and Cal-ISO markets for calculating refunds, had not retroactively reset the tariff rates in those markets. The Ninth Circuit Court found that although "FERC has authority to state retroactively what a 'just and reasonable' rate would have been pursuant to its refund authority, Congress did not provide FERC with retroactive ratesetting authority over non-jurisdictional sellers" like Bonneville.

In November 2012, FERC issued a ruling in the FERC California Refund Docket determining that a remedy, if any, for the Summer 2000 Transactions would not be made on a "market-wide" basis but rather would be based on the individual tariff violations of the sellers. Under a "market-wide" remedy, the potential damages could be significantly higher since the price of every sale or related transaction could be retroactively adjusted downward, irrespective of whether the seller violated the tariff in the hour at issue. The California Parties have filed an appeal of the foregoing FERC determination with the Ninth Circuit Court. The appeal has been stayed pending final resolution of a number of pending matters at FERC.

In a separate proceeding at FERC as part of the FERC California Refund Docket, an administrative law judge ("ALJ") appointed by the FERC Commissioners conducted a hearing in 2012 to make certain findings related to the Summer 2000 Transactions and the Exchange and Multi-day Transactions. In February 2013, the ALJ issued his findings to the FERC Commissioners.

In the ALJ's findings he determined that Bonneville violated the tariff with 84 Summer 2000 Transactions. Approximately 11,000 bids were made into the Cal-ISO market during the subject period. Assuming, among other things, that the ALJ's proposed tariff violation conclusions were to be adopted by the FERC Commissioners (and sustained upon court review, if any, challenging such a determination) and that the approach not to impose market-wide mitigation for the Summer 2000 Transactions were to be upheld upon appeal, Bonneville estimates that its potential refund liability to the California Parties for the Summer 2000 Transactions would not be significant.

In the February 2013 findings, the ALJ also found that the prices charged for all of Bonneville's Exchange and Multi-day Transactions were at unjust and unreasonable rates and are subject to refund. The ALJ's proposed refund methodology could result in potential liability by Bonneville to the California Parties of approximately $108 million, including interest through February 2013, assuming the FERC Commissioners adopt it and the Court of Federal Claims April 2013 Order stands. The ALJ's opinion is advisory and the matter is reserved for final administrative determination by the FERC Commissioners. Bonneville believes that the ALJ's opinion is erroneous in a number of material respects and has filed, with the FERC Commissioners a brief identifying errors in the ALJ's opinion. Among other things, Bonneville argues that under the Ninth Circuit Court's rulings referenced above, FERC does not have authority to order refunds by non-jurisdictional utilities such as Bonneville or to modify Bonneville's rates. The California Parties have filed their response to Bonneville's brief. The parties in the FERC proceeding await a ruling from the FERC Commissioners.

On April 4, 2013, the Court of Federal Claims issued orders on separate motions, one filed by the United States Department of Justice on behalf of Bonneville and another Federal power marketing administration, and one filed by the California Parties. In the former motion, the United States Department of Justice asked the Court of Federal Claims to reconsider its May 2012 Order on liability in light of the Ninth Circuit Court's September 2012 ruling that FERC had not retroactively reset tariff rates. The Court of Federal Claims ruled that the Ninth Circuit Court's opinion was not dispositive of the contract liability issue in the California Breach Claims litigation because the Ninth Circuit Court did not address how the FERC-mitigated prices affected the California Parties' breach of contract claims against Bonneville.

In the latter motion, the California Parties sought certain clarifications of the May 2012 Order. In the April 4, 2013 order, the Court of Federal Claims clarified that "if and when" FERC resets the applicable prices, Bonneville will be liable to the California Parties for the value that it received in excess of the mitigated prices.

In April 2013, the Chief Judge of the Court of Federal Claims named a new judge to preside over the California Breach Claims litigation. The new judge has stated that she will review all substantive orders and opinions of the prior judge in the California Breach Claims litigation.

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

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

Federal Refund Law. In Fiscal Year 2005, Congress enacted the Energy Policy Act of 2005 ("EPA-2005"), which subjects Bonneville to FERC jurisdiction, after the effective date of the legislation, for purposes of establishing refund liability. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005." For a description of litigation between SCE and Bonneville arising out of developments in West Coast energy markets in 1999-2000, 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 "FISCAL YEARS 2012-2028 REGIONAL POWER SALES BACKGROUND."

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

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

Seventeen separate Preference Customers elected to purchase Slice/Block as the type of service they will receive under their Long-Term Preference Contracts. The remaining Preference Customers elected to take Load Following service. In aggregate, sales of the Slice component of Slice/Block under the Long-Term Preference Contracts represent approximately 26.9 percent of Federal System generation, although this amount will decline slightly beginning in Fiscal Year 2014 when a Slice/Block Customer with a 0.18549 percent share of Slice (which is equivalent to approximately 13 annual average megawatts on a planned basis) will convert its Slice purchase to a Block power product purchase. By contrast, Bonneville sold approximately 22.6 percent of the Federal System generation as Slice under the previous contract methodology. Preliminary forecasts for Fiscal Year 2014 indicate that loads met under Load Following service will be approximately 3,300 annual average megawatts. Loads met by Slice/Block service will be approximately 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.

The aggregate amount of power loads to be served at Tier 1 PF Rates has been set at 7,186 annual average megawatts with the commencement of service to a new Preference Customer, Public Utility District No. 1 of Jefferson County, Washington ("Jefferson County PUD").

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 70 annual average megawatts for a potential sale to DOE, and (ii) up to 250 annual average megawatts in aggregate, if necessary, for new Preference Customers (the limit through Fiscal Year 2028). Bonneville cannot predict whether potential public utilities in addition to Jefferson County PUD will commence operation or become Preference Customers. In addition, Bonneville's obligation to sell power at Tier 1 PF Rates would be reduced if and to the extent that specified existing Federal System resources, including the Columbia Generating Station, were to decline in capability.

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 (if any) to be provided to DSIs, 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 provides 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 58 annual average megawatts of Tier 2 loads in Fiscal Year 2013, approximately 75 annual average megawatts in Fiscal Year 2014, and approximately 18 annual average megawatts in Fiscal Year 2015. The amount of Tier 2 Loads that Preference Customers will place on Bonneville for Fiscal Years 2016 through 2019 will not be determined until the power rates proceeding applicable to the related fiscal year of Tier 2 Loads. 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 through 2030 (approximately 5,900 of 7,000 average annual 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 the Council's Regional conservation target and public power's (Bonneville, Preference Customer and other public agency loads) share, which in aggregate constitutes a 42 percent share of the Council's overall Regional target. The public power share equates to approximately 504 annual average megawatts of savings in aggregate over the five-year period of the Sixth Power Plan (2010 — 2014). Bonneville and its power customers have already achieved over 300 annual average megawatts of conservation toward the public power target and plan to achieve at least an additional 200 annual average megawatts of conservation within the five-year period. Achieving the conservation targets helps Bonneville manage future load-growth and minimizes reliance on development of other resources in order to meet demand. See "—Bonneville's Resource Program and Bonneville's Resource Strategies—Electric Power Conservation."

Bonneville's Resource Program and Bonneville's Resource Strategies. In September 2012, 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, which as Preference Customers, may seek to 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.

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.

Bonneville's 2012 White Book and 2013 Resource Program. In February 2013, Bonneville issued the 2012 White Book and the 2013 Resource Program. These documents evaluate whether Bonneville may need to acquire resources to meet its power supply obligations, primarily to customers under the Long-Term Regional Dialogue Contracts, and the best means by which to meet those needs. The Resource Program also supplies information to Bonneville's customers about resources available to meet their needs. The planning horizon for the White Book and Resource Program extends through Operating Year 2021. In addition to examining annual energy needs, the White Book Needs Assessment analyzed Bonneville's needs for monthly/seasonal heavy load hour energy, capacity needs for extreme weather events and hourly balancing reserves through Operating Year 2021.

The 2013 Resource Program outlines how Bonneville proposes to meet its obligations. The conclusion of the Resource Program reflects that Bonneville can satisfy much of its expected supply obligation through Operating Year 2021 with conservation and short-term power purchases from the wholesale power market. The Resource Program includes an Action Plan that outlines many key actions that Bonneville plans to undertake to help mitigate its energy, capacity and balancing reserves needs. The Action Plan also outlines key areas that Bonneville feels should be monitored to insure that the Bonneville resource strategy is still appropriate.

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 2013 conservation program, an annual average megawatt of energy savings will cost, on average, approximately $1.9 million increasing to approximately $2.0 - $2.1 million in Fiscal Year 2014. Bonneville estimates that it achieved new conservation savings of 91 annual average megawatts in 2010, 118 annual average megawatts in Fiscal Year 2011, and approximately 60 annual average megawatts in Fiscal Year 2012. 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 continued 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. 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. See "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" are set at approximately $77 million per year from Fiscal Year 2012 through Fiscal Year 2019. Thus, actual aggregate cash payments to the Regional IOUs are set at approximately $182 million per year during the 2012-2013 Rate Period and Bonneville has made payments in Fiscal Years 2012 and 2013 consistent with the foregoing terms. 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 2012, the un-recouped aggregate overpayment of Residential Exchange Program benefits was approximately $536 million. The recoupment period for Refund Amounts ends in Fiscal Year 2019.

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 Years 2011 and 2012 was approximately $650 and $643 million, with $422 and $453 million in Direct Costs and $228 and $190 million in Operational Impacts, respectively. Of the Operational Impacts in Fiscal Years 2011 and 2012, $71 and $38 million was attributable to Replacement Power Purchase Costs and $157 and $152 million was attributable to Foregone Power Revenues, respectively.

The $31 million increase in Direct Costs from Fiscal Year 2011 to Fiscal Year 2012 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 $32 million decrease in Replacement Power Costs and $5 million in Foregone Power

Revenues from Fiscal Year 2011 to Fiscal Year 2012 was caused primarily by decreased prices due to energy market conditions and the updated theoretical load used to calculate replacement purchases and foregone revenues.

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 approximately 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 approximately $20 million in Fiscal Year 1981 to $150 million in Fiscal Year 1991. After the issuance of the first biological opinion affecting Federal System operations, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in Fiscal Year 1995. Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council 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 addressed court-identified deficiencies arising from legal challenges to prior Columbia River System biological opinions. In general, the 2008 Columbia River System Biological Opinion adopted 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 called 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 were and 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 approximately 80 percent of the costs of the modifications, which is the estimated portion of such costs assigned by law or administrative practice to be recovered in Bonneville's power rates. Bonneville does not expect that the modifications will be financed with Bonneville's statutory borrowing authority with the United States Treasury. As with other appropriated investments in the Federal System, Bonneville depreciates the portion of the costs to be recovered in power rates from the dates the related capital facilities are placed in service through their expected useful lives. These modifications will be implemented over many years; thus, their costs will gradually be added to Bonneville's rates and appropriated repayment responsibility as they are placed in service.

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 concluded 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 did 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 Federal Columbia River Power System Biological Opinion." A number of interests challenged the 2010 Supplemental Columbia River Power 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 Federal Agencies are complying with this order and anticipate a Supplemental Federal Columbia River Power System Biological Opinion will be issued at the end of calendar year 2013. 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. The Federal Agencies are complying with the order and have annually filed Fish Operations Plans with the court. 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 2008 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 a ten year period. 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 approximately $994 million over the ten-year period ending September 30, 2018. Bonneville estimates that approximately 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.

Costs and Consequences of the 2010 Supplemental 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 approximately 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 approximately $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.

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the Office of Management and Budget, DOE, and other agencies agreed to provide for certain Federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision authorizes Bonneville to exercise its Northwest Power Act authority to implement fish and wildlife mitigation on behalf of all of a Federal System project's authorized purposes under Federal law; not just those relating to the delivery of generation and transmission services to customers, but also non-power purposes such as irrigation, navigation, and flood control. At the end of the fiscal year, Bonneville is required to recoup (i.e., take a credit for) the portion allocated to non-power purposes. Included in this credit are Direct Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was approximately $123 million, $85 million, and $77 million in Fiscal Years 2010, 2011, and 2012, respectively. Forecasts of these 4(h)(10)(C) credits are treated as revenues in Bonneville's ratemaking process. At the close of each fiscal year, they are applied against Bonneville's payments to the United States Treasury. The 4(h)(10)(C) credits are initially taken based on estimates and are subsequently modified to reflect actual data. An important cost that may be recouped under section 4(h)(10)(C) is that of Replacement Power Purchases necessitated by the loss of generation arising from certain changes to hydroelectric system operations for the benefit of fish and wildlife. These costs occur annually and are highest in low water years when, historically, the output of the hydro-system is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

Council's Fish and Wildlife Program. In 2000, the Council 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 $249 million in Fiscal Year 2012. Fiscal Year 2013 expenses and capital program investments are forecast to be $243 million and $67 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 to FERC in August 2011. On December 31, 2012, FERC provided final approval of 2012-2013 Final Power and Transmission Rate Proposal (as approved by FERC, the "Final 2012-2013 Rates"). Certain limited features of the power rates portion of

the Final 2012-2013 Rates (the "Final 2012-213 Power Rates") relating to potential load growth of industrial end-use customers of Preference Customers have been challenged in the Ninth Circuit. See "BONNEVILLE LITIGATION—Final 2012-2013 Power Rates Challenges."

The Final 2012-2013 Power Rates reflect for the first time Bonneville's transition to Tiered Rates. See "FISCAL YEARS 2012-2028 REGIONAL POWER SALES BACKGROUND—Regional Power Sales—Power Sales to Preference Customers." The Final 2012-2013 Power Rates adhere to Bonneville's 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. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met." The Final 2012-2013 Power Rates also continue, among other features, the use of a rate level adjustment mechanism (the "Cost Recovery Adjustment Clause" or "CRAC") that allows power rate levels to be increased at the beginning of either of the two years of the rate period, in each case according to financial results as of the end of each of the prior fiscal years, The CRAC did not trigger in Fiscal Year 2011 for Fiscal Year 2012, or in Fiscal Year 2012 for Fiscal Year 2013. Based on internal Bonneville estimates, a CRAC is unlikely to trigger in Fiscal Year 2013 for Fiscal Year 2014.

A very large portion of the electric power that Bonneville markets is sold to Preference Customers. PF Preference Rate levels under the Final 2012-2013 Power Rates increased over rates in effect for Fiscal Years 2010 and 2011 (the "2010-2011 Power Rates"). An exact comparison of the current power rate levels and past power rate levels is complicated because of a change to Tiered Rates, but for comparison, Bonneville uses the average Tier 1 net cost as a close approximation of the average PF Preference Rate under the 2010-2011 Power Rates. The average Tier 1 net cost in the Final 2012-2013 Rates represents an increase of approximately 7.8 percent over average PF Preference Rates in the Final 2010-2011 Rates, from approximately $26.82 per megawatt hour to $28.90 per megawatt hour. 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. This represents an increase of approximately 4.8 percent from the Fiscal Year 2010-11 Rate Period. Bonneville's Final 2012-2013 Rates for Power Services also include a determination of rate levels for several power products for Tier 2 loads. Bonneville currently sells less than 100 average megawatts of power at Tier 2 rate levels. Under the Final 2012-2013 Power Rates, Tier 2 rate levels are set at between $46.48 per megawatt hour and $48.69 per megawatt hour, depending on the year and the type of Tier 2 power product.

Bonneville sells approximately 320 annual average megawatts of electric power to DSIs in the current power rate period. The IP Rate level established for DSI service in the Final 2012-2013 Power Rates represents an increase of five percent over such rates in the prior rate period: from approximately $34.59 per megawatt hour to $36.32 per megawatt hour (in each case 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.

The foregoing power rates exclude transmission charges and approximately $77 million per fiscal year in amounts that Bonneville has refunded or will refund to Preference Customers in the current rate period under the Residential Exchange Settlement Agreement. See "—Residential Exchange Program."

By law, Bonneville establishes rates to recover its costs. More particularly, Bonneville establishes power rates to meet its payment obligations for Power Services operations, which payment obligations include those under the Cowlitz Falls Project Agreements.

Risk Mitigation Tools Underlying the Initial Proposed Power Rates for the 2014-2015 Rate Period

Bonneville announced its initial rate proposals for Fiscal Years 2014-2015 on November 8, 2012. Under the Initial Proposal, Bonneville has initially proposed to increase power rates generally. Based in part on the Initial Proposal, Bonneville is completing the Final 2014-2015 Rate Proposal and will submit it to FERC for review in late July or early August 2013. For a description of the initially proposed changes in power rates and levels see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville's Power and Transmission Rates Proposal for the 2014-2015 Rate Period."

With regard to tools to manage risks related to maintaining sufficient financial resources to meet all costs timely and in full, including scheduled payments to the United States Treasury, Bonneville continues the use of certain features (in some cases slightly modified) from prior final power rates. For instance, the proposed power rates would continue the use of (i) "base rates" for Regional power sales that are set at levels Bonneville believes to be sufficient to yield a reasonably high probability of sufficient net revenue, and (ii) a CRAC that can increase certain power rate (primarily PF Preference Rates other than the rate for Slice) levels at the beginning of either of the two years of the rate period, in each case according to financial results. Bonneville proposes to use net revenues as measured since the beginning of Fiscal Year 2013 ("Accumulated Net Revenue" or "ANR") as the measure for determining whether a CRAC will trigger. Changes in ANR generally mirror changes in financial reserves, and net revenue is an audited metric while financial reserves level is not. The CRAC would trigger if Power Services' ANR is forecast to be below certain

thresholds at the beginning of either of the two years of the rate period. As proposed in the Initial Proposal, the CRAC would trigger if Power Services' ending Fiscal Year 2013 ANR is forecast in July 2013 to be below negative $203 million, in which case Bonneville would increase the level of certain rates for Fiscal Year 2014 to collect up to an additional $300 million without another full rate proceeding, depending on how far below the CRAC threshold the ANR falls. As currently proposed, if Power Services' ending Fiscal Year 2014 ANR is forecast in September 2014 to be below negative $196 million, Bonneville would increase certain rate levels for Fiscal Year 2015 to collect up to an additional $300 million without another full rate proceeding.

By way of example, if Bonneville were to forecast that Power Services' financial reserves level (as measured by forecast ANR) will be negative $100 million as of the end of Fiscal Year 2013, the CRAC amount would be equal to $100 million, thereby increasing certain rate levels to generate an additional $100 million. If the projected deficit in the Power Services' financial reserves level is forecast to be greater than $100 million but less than or equal to $500 million, the CRAC amount would be $100 million plus half of the amount by which the projected deficit exceeds $100 million. Thus, if Power Services' financial reserves level is forecast to be negative $300 million, the CRAC amount would be $200 million. Notwithstanding the foregoing, all financial reserves in the Bonneville Fund, regardless of whether they are derived from Power Services operations or not, are available to meet Power Services costs, including payments by Bonneville under the Cowlitz Falls Project Agreements.

Based on Fiscal Year 2013 second quarter results, an assumption that the CRAC in the Final 2014-2015 Rate Proposal is similar to the CRAC assumed in the Initial Proposal, and estimates and forecasts of numerous factors for the remainder of Fiscal Year 2013, Bonneville believes that there is a low probability that the proposed CRAC would trigger for Fiscal Year 2014.

Under the power rates portion of the Initial Proposal, Bonneville proposes to utilize updated versions of the National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment ("NFB Adjustment") and Emergency National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Surcharge ("Emergency NFB Surcharge"). These features are part of the current power rates construct and were part of power rates in the period preceding the current power rates period. These two features would enable Bonneville to recover additional amounts during the 2014-2015 Rate Period to address unexpected costs or decreases in revenue that could arise from Endangered Species Act ("ESA") litigation relating to the Federal System. See "—Fish and Wildlife—Endangered Species Act."

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

Bonneville also proposes to continue a feature parallel to, but the reverse of, the CRAC, referred to as the Dividend Distribution Clause ("DDC"). The DDC could decrease certain power rate levels in either year of the rate period, also based on financial results as measured by ANR calculated from the beginning of Fiscal Year 2013. In the Initial Proposal, the DDC would trigger for Fiscal Year 2014 rates if ending Fiscal Year 2013 Power Services' ANR is forecast to be above $547 million, and would trigger for Fiscal Year 2015 rates if ending Fiscal Year 2014 ANR is forecast to be above $554 million. For both years, the ANR threshold corresponds to $750 million in ending Power Services' financial reserves. Bonneville does not expect the DDC to trigger for Fiscal Year 2014.

The power rates portion of the Initial Proposal reflects Bonneville's expectations and assumptions when developing the Initial Proposal. Bonneville's final proposed power rates, rate features, and rate levels could differ, perhaps substantially, from those included in the Initial Proposal.

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 FPA 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 approximately $791 million in revenues from the sale of transmission and related services, or approximately 24 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 2012.

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 the current rate period (Fiscal Years 2012-2013), a large Preference Customer that purchases very little transmission for its own resources pays 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 2013 through 2015 averaging approximately $610 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 limited 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 Integration 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 were $44 million in Fiscal Year 2013 and will be $40 million in Fiscal Year 2014. It is possible that the amount of such credits could increase in future years depending on the development of new generation projects (particularly wind projects) that 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 Integration 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 requires that the Network Integration service transmission system investments be made. 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 approximately $120 million in bonds to fund construction of the project.

Since 2007, Bonneville has entered into a number of master lease agreements with several leasing entities. Under these master lease agreements Bonneville has entered into individual commitments to lease-purchase for a period of seven years or less, a wide variety of transmission facility replacements and improvements throughout the Federal Transmission System. Bonneville's lease-purchase payments are pledged to the payment of certain bank loans entered into by the leasing entities and the proceeds of the bank loans were and are being used to fund the acquisition, construction, installation, and equipping of the related leased facilities. The aggregate principal amount of bank loans outstanding or available to be drawn by the leasing entities under these master lease agreements is approximately $718 million.

As the respective lease periods under current and future master lease agreements approach their scheduled termination dates, Bonneville expects that it will enter into new, long-term lease-purchases for the related facilities. A leasing entity will pledge the lease revenues from Bonneville under a new, long-term lease-purchase agreement to the payment of debt service on long-term bonds and the proceeds of the bonds will be used to pay off the prior short-term bank loans, which funded construction and installation of the related facilities.

In July 2012, Bonneville transitioned from a short-term lease-purchase for certain transmission facilities to a long-term lease-purchase with the Port of Morrow, Oregon (the "Port"). The Port issued $85 million in long-term bonds (having a final maturity of September 1, 2042), and used the proceeds to acquire the related facilities from the prior owner. The prior owner used the funds to pay in full bank loans that it had incurred to finance construction of the facilities.

Bonneville's lease payments under the foregoing lease-purchase arrangements are not conditioned on the completion, suspension, or termination of the related facilities. All of the foregoing lease-purchase bonds and bank loans are secured solely by Bonneville's payments under the related lease-purchase agreement. The principal amounts associated with the master leases are included in the Federal System audited financial statements as "Non-Federal Debt."

As part of Bonneville's annual budget submitted to Congress for Fiscal Year 2014, Bonneville forecasted that expenditures from funds provided under lease-purchase agreements will average approximately $284 million annually over Fiscal Years 2012-2018. 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.

See "BONNEVILLE LITIGATION—Lease-Purchase Program Property Taxes."

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 final 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 approximately $4.32 per megawatt hour under the Final 2012-2013 Rates.

As did the prior rates, the Final 2012-2013 Rates include a Transmission Services 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 Transmission System. This rate recovers the costs of the reserves described above. The Variable Energy Resource Balancing Rate averages approximately $5.69 per megawatt hour of wind generation, assuming wind energy production is approximately 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—Wind Generation Integration into the Federal Transmission System."

Initial Proposed Rates for Transmission and Ancillary Services for the 2014-2015 Rate Period

Bonneville is proposing a thirteen percent increase in its transmission rates mainly due to continued efforts to maintain Federal Transmission System reliability and meet increasing demands for transmission in the Pacific Northwest. If adopted, the proposal would be the first transmission rate increase in eight years.

A number of factors are leading to increased spending and the proposed transmission rates. Construction of new lines and replacements to maintain reliability and facilitate the integration of renewable resources, such as wind, accounts for slightly more than one half of the proposed thirteen percent increase. Increased mandatory compliance requirements and additional cyber security and physical security requirements and other operational and maintenance expenses account for slightly less than one half of the proposed transmission rate increase.

Under a partial settlement of the transmission and ancillary service portion of the rate proceeding for Fiscal Year 2014-2015, Bonneville's rate to balance renewable resources, primarily wind generation, would decline slightly. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development—Wind Generation Integration into the Federal Transmission System."

Bonneville has agreed to compensate certain non-hydroelectric generators (primarily wind generators) for certain costs that they incur that cannot be addressed by substituting (displacing) their generation with Federal System hydroelectric power in oversupply events. On April 12, 2013, Bonneville released a revised oversupply rate proposal wherein the costs of compensation to non-hydroelectric generators (and certain other costs to Bonneville) arising from oversupply management actions would be allocated in a supplemental Bonneville transmission rate to customers using the Federal Transmission System during oversupply events. Bonneville has proposed that the oversupply rate be in effect from March 31, 2012 through September 20, 2015, to recover over-generation costs already incurred as well as future costs for the period the new rate would be in effect. Bonneville expects to issue a final decision and record of decision on August 28, 2013.

See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville's Power and Transmission Rates Proposal for the 2014-2015 Rate Period—Initial Proposed Oversupply Rates," and "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Wind Generation Development—Bonneville Policies Regarding Over-generation from High Water and High Wind."

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 a few operating as a balancing authority area in the Region. ColumbiaGrid is not an "RTO" under FERC policies since ColumbiaGrid has a relatively restricted scope of operations. ColumbiaGrid focuses on coordinating Regional transmission planning and expansion, assisting participating utilities in meeting their transmission planning obligations, and providing members with information about system infrastructure and transmission utilization. ColumbiaGrid would have increased responsibilities to implement the FERC Order 1000 for the Region and for the interregional transmission planning processes. 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 approximately $3 million per year. Bonneville and the other participants in ColumbiaGrid continue to work on the development of ColumbiaGrid's operations.

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

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

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

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

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

MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards

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

Bonneville Ratemaking Procedures

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

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

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

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

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

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

Judicial Review of Federal Energy Regulatory Commission Final Decision

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

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

Power Customer Classes

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

Other Firm Power Rates

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

Surplus Energy

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

Limitations on Suits against Bonneville

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

Laws Relating to Environmental Protection

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

Energy Policy Act of 2005

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

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

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

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

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

2010 Dodd-Frank Act and Bonneville

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

Bonneville participates extensively in OTC forward 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. Bonneville is also engaged from time to time in exchange-traded, power-related futures to manage risk in its market purchases and sales of electricity. Bonneville's futures/financial program is governed by Bonneville's transaction risk management policies that establish limits around open positions and posted margins. Bonneville does not currently hold any other types of financial swaps or future contracts such as interest rate swaps. For further discussion about Bonneville's transaction risk management policies, see "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

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

Other Applicable Laws

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

Columbia River Treaty

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

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

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

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

Although the Treaty does not expire by its own terms, either the United States or Canada may elect to terminate it by providing not less than ten years' notice, with the earliest time for termination occurring in September 2024. 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 after this date. The United States Entity expects to make a recommendation to the United States by the end of 2013. 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, including payments under the Cowlitz Falls Project Agreements.

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 has initiated a cap and trade platform that became active in 2013 that would establish a carbon price in California. Other Western states or Canadian provinces could join the cap and trade platform through the Western Climate Initiative. The pricing of carbon is intended to disfavor the use of high carbon intensity resources, particularly coal. However, none of the generating facilities of the Federal System are fueled by carbon-based fuels. The Federal System generating facilities are primarily hydroelectric resources, or, in the case of Columbia Generating Station, nuclear-fueled. Therefore, it is unlikely that a carbon price would directly affect the cost of the output of the Federal System. However, a carbon price may increase the market price of electricity.

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

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

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

Preparedness and Cyber Security

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

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

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

Wind Generation Development and Integration into the Federal Transmission System

As the owner/operator of the Federal Transmission System, the largest bulk transmission system in the Region, Bonneville is responsible for transmitting electric power from and integrating most of the new wind generation projects that are located in the Region or that are transmitted into or through the Region. Bonneville estimates that 4,847 megawatts of wind generation facilities are now interconnected to the Federal Transmission System. Bonneville expects that an additional 60 megawatts of wind power will be integrated by the end of September 2014. The rate of growth of wind energy development in the Region has slowed; nonetheless, 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.

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 approximately 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, within limits, to spill water to aid downstream migrant fish. This reduces the amount of water that may be run through turbines to generate power and thereby limits the ability of the Federal System hydroelectric resources to respond to decrements in wind generation by increasing hydroelectric generation. Conversely, too much spill may also be damaging to downstream migrant fish by increasing total dissolved gases in the water. Therefore, in certain circumstances of high stream flows and high turbulence, water must run through hydroelectric turbines (which unavoidably creates electric power that must be consumed) to quell spill and suppress the amount of dissolved gases. Bonneville has developed processes to assure that wind generation integration does not adversely affect meeting CWA and ESA fish requirements by establishing the ability to displace non-hydroelectric generation with Federal System hydroelectric energy. See "—Bonneville Policies Regarding Over-generation from High Water and High Wind." 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."

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 Federal Transmission System, and to bring new resources into the marketplace for balancing services and reserves that can match wind generation variability. These initiatives

are intended to reduce dependence on the Federal System generating resources for balancing services and dampen the increase in Bonneville's wind integration costs.

Costs of Bonneville's wind integration efforts are recovered in its rates, with some costs covered by financial reserves. With respect to wind integration in particular, Transmission Services has established cost recovery in its transmission and ancillary services rates to reflect the cost of obtaining adequate operating reserves from generating facilities to support the integration of new generating resources (especially variable resources such as wind power). See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

Bonneville Policies Regarding Over-generation from High Water and High Wind

Beginning in Fiscal Year 2010, Bonneville began experiencing periods of significant surplus hydropower combined with high levels of wind generation and low levels of energy demand. Further, in these periods certain Federal System hydroelectric facilities were operating pursuant to requirements which in effect require that water run through turbines to reduce spill turbulence and the resulting concentrations of dissolved gas that are harmful to ESA-listed fish species. The need to generate hydroelectric power to avoid spill has led Bonneville to establish certain arrangements in which Bonneville uses Federal System hydroelectric generation to displace other generation at times when (i) aggregate electric generation threatens to exceed electric system demand, and (ii) continued hydroelectric generation is necessary to keep dissolved gas concentrations within acceptable limits. Bonneville refers to these conditions as "over-generation" or "oversupply" events.

In May 2011 Bonneville issued certain "Interim Policies" under which Bonneville displaced non-Federal generation with Federal power in its balancing authority area with Bonneville's power provided at no cost to the displaced non-Federal generators. In addition, under the Interim Policies, Bonneville required non-Federal generators (wind resources primarily) to curtail generation during over-generation events. Under the Interim Policies, forced displacement occurred only when required and only as a last resort to avoid harmful total dissolved gas from exceeding certain thresholds established to protect fish. The Interim Policies did not provide for Bonneville to financially compensate the displaced generators. Several wind generators and transmission customers filed complaints with FERC alleging that the Interim Policies did not provide transmission service on terms and conditions that were comparable to those under which Bonneville provides transmission service to itself. In addition, several parties filed petitions with the Ninth Circuit Court in July 2011, seeking review of Bonneville's Interim Policies. These Ninth Circuit Court cases are set to proceed in September 2013. In December 2012, FERC determined that Bonneville's Interim Policies did not provide for comparable transmission service and ordered Bonneville to file tariff revisions.

In March 2012, Bonneville filed with FERC a proposed Open Access Transmission Tariff revision, referred to as the Oversupply Management Protocol ("OMP"), to manage over-generation events. The OMP provides that in over-generation events, Bonneville will displace generation from projects in its balancing authority area using Federal System hydroelectric generation at no cost to the displaced generators and will compensate non-Federal generators for eligible costs they incur from having been displaced during over-generation events. Eligible costs 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.

Under the OMP, Bonneville first displaces generators that do not incur costs as a result of displacement, and then displaces generators in the order of least costly to most costly to displace until adequate generation reductions have been achieved. Further, all displaced generators receive Federal System hydroelectric power to meet their scheduled transmission needs. Bonneville also informed FERC of Bonneville's initial rate proposal to allocate the costs Bonneville incurred under the OMP: 50 percent to recovery in Bonneville's power rates, and 50 percent to wind generators that receive compensation under the OMP. Shortly thereafter, several parties filed petitions with the Ninth Circuit Court seeking review of the OMP. These Ninth Circuit cases are stayed through September 13, 2013.

On December 20, 2012, FERC conditionally approved the terms and conditions of the OMP provided that Bonneville alter its proposed allocation of the costs. FERC stated that Bonneville should allocate the costs of the OMP based on use of the Federal Transmission System at the time of the over-generation event, and also ordered changes to the terms and conditions of the OMP should it be filed in the future. In March 2013, Bonneville re-filed the OMP with FERC, making certain changes to address FERC's order, and asking for approval through the end of September 2015. In April 2013, Bonneville issued a supplemental rate proposal proposing to allocate the costs under the OMP in a manner similar to that proposed by FERC. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville's Power and Transmission Rates Proposal for the 2014-2015 Rate Period—Initial Proposed Oversupply Rates." On May 3, 2013, certain Preference Customers filed petitions for review in the Ninth Circuit Court challenging Bonneville's March 2013 decisions with respect to the OMP. Additional parties filing by the deadline of May 30, 2013 are PacifiCorp, Transalta, Northwest & Intermountain Power Producers Coalition, and Iberdrola.

In Fiscal Year 2011, Bonneville displaced approximately 97,500 megawatt-hours of generation with energy from the hydroelectric system under oversupply events. The Interim Policy did not include a mechanism to reimburse generators for the cost of displacement. Under the original OMP, from March 2012 to August 15, 2012, Bonneville displaced 49,654 megawatt hours of generation resulting in eligible displacement costs of approximately $2.7 million. No over-generation events have occurred yet in 2013, and given the comparatively low river flows in Fiscal Year 2013, and actions taken by Bonneville, Bonneville believes there is a reduced likelihood of financially significant over-generation events occurring in the remainder of Fiscal Year 2013. Bonneville estimates that on an expected value basis, under the proposed OMP, it will compensate non-Federal generators approximately $10 million per fiscal year in aggregate, on average, to reduce electricity generation if oversupply events continue to occur. Under extreme conditions, compensation could exceed $50 million in a given fiscal year.

The OMP does not address any claims for damages associated with Bonneville's implementation of its Interim Policies. All of Bonneville's costs arising from over-generation are recovered in its rates. See "TRANSMISSION SERVICES—Bonneville's Transmission and Ancillary Services Rates."

Columbia Generating Station and Energy Northwest's Purchase of Uranium

Bonneville receives all of the project capability from the Columbia Generating Station and covers the costs thereof through various agreements, described herein under BONNEVILLE FINANCIAL OPERATIONS—Energy Northwest Net Billing Agreements." The Columbia Generating Station project costs include debt service on bonds and other debt obligations for capital and other expenditures for the project. The Columbia Generating Station is owned and operated by Energy Northwest, and is licensed by the Nuclear Regulatory Commission to operate through 2042.

In August 2012, Energy Northwest issued approximately $782.7 million of bonds, a large portion of which financed the acquisition of nuclear fuel under an integrated set of transactions involving Energy Northwest, DOE, the Uranium Enrichment Corporation ("USEC") and the Tennessee Valley Authority ("TVA") (the "Uranium Program"). Under the Uranium Program, DOE provided approximately 9,082 metric tons of depleted uranium hexafluoride ("Uranium Tailings") at no cost to Energy Northwest. DOE has also agreed to store the Enriched Uranium through as late as December 31, 2022, when Energy Northwest's expected need for storage ends. Energy Northwest is obligated to pay DOE the actual cost of storage and transfer between USEC and DOE, not to exceed $5 million. The Uranium Tailings were physically transferred from DOE ownership to Energy Northwest ownership at a uranium enrichment facility operated by USEC in Paducah, Kentucky for enrichment by USEC. USEC has enriched the Uranium Tailings to a level necessary for fabrication into commercial nuclear fuel (the Uranium Tailings as so enriched, the "Enriched Uranium"), Energy Northwest has approved the quality of the Enriched Uranium, and USEC has transferred the Enriched Uranium to DOE at its adjacent site in Paducah, Kentucky for storage. In June 2013, Energy Northwest completed its payments to USEC in the amount of $688 million, in aggregate, for its enrichment services.

Under the Uranium Program, DOE is also responsible for the waste material after enrichment (newly created uranium tails). Energy Northwest has assumed the risk of the loss of the Enriched Uranium during DOE storage, although Energy Northwest has stated that it believes that the potential that the Enriched Uranium will be damaged or lost during storage is very low.

TVA has contracted to purchase from Energy Northwest approximately two-thirds of the value of the Enriched Uranium produced from the Uranium Program. The value is represented in rights to certain quantities of Enriched Uranium and of "separative work units," which represent the process by which the assay or weight of the natural uranium is increased. Payment from, and ownership transfer to, TVA are to occur beginning in 2015 and ending in 2022. If the maximum is delivered to TVA, Energy Northwest will receive approximately $730.3 million from TVA. Energy Northwest may terminate the sale if TVA were to breach its purchase obligation, in which case Energy Northwest would be free to use the Enriched Uranium and separative work units in connection with the Columbia Generating Station or sell them to others.

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, 2012, Bonneville had repaid $10.9 billion of principal of the Federal System investment and has $3.8 billion principal amount outstanding with regard to such appropriated investments and $3.4 billion principal amount 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 $12 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, $3.4 billion of bonds were outstanding as of the end of Fiscal Year 2012. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 annual average megawatts. Of the $7.7 billion in United States Treasury borrowing authority, $1.25 billion is available for electric power conservation and renewable resources, including capital

investment at the Federal System hydroelectric facilities owned by the Corps and Reclamation, and $6.45 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable Federal Government institutions at the time of issuance. As of the end of Fiscal Year 2012, the interest rates on the outstanding bonds ranged from 0.2 percent to 6.1 percent with a weighted average interest rate of approximately 3.6 percent. The original terms of the outstanding bonds vary from 4 to 30 years. As of the end of Fiscal Year 2012, Bonneville's outstanding bonds issued to the United States Treasury included $300 million in variable rate bonds at an average interest rate of 0.2 percent at such time. The term of the bonds is limited by the average expected service life 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") governing the terms by which Bonneville borrows from the United States Treasury. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating advances can be made available on as short as one day's notice and have a maximum repayment period of one year, although Bonneville may extend the maturities an additional year by exercising certain rights that would re-establish applicable interest rates. Nothing in the banking arrangement increases the statutory limit on the $7.7 billion aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time.

Coincident with the entry into the Obligation Purchase MOU, Bonneville and the United States Treasury entered into an Investment Memorandum of Understanding ("Investment MOU") that governs investments in the Bonneville Fund beginning October 1, 2008. Under prior practice, Bonneville earned 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 MOU 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 aggregate planned capital expenditures comparable to 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 subsequent plans, 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 2010, 2011, and 2012 were approximately $762 million, $1.013 billion, and $955 million, respectively. Of these amounts, Bonneville's capital expenditures funded by borrowing from the United States Treasury were approximately $604 million, $799 million, and $651 million in Fiscal Years 2010, 2011, and 2012, respectively. Bonneville forecasts that its aggregate capital expenditures will be approximately $927 million in Fiscal Year 2013 and will average approximately $1.048 billion per year in the following four fiscal years. The foregoing capital spending amounts do not include capital expenditures for the Columbia Generating Station, the costs of which are also funded by Bonneville pursuant to the Net Billing Agreements as described in "—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 for energy efficiency initiatives. Energy Northwest has developed a long-term capital development strategy for the Columbia Generating Station in view of a recent 20 year operating license extension, evolving and expected guidance from the Nuclear Regulatory Commission and other factors. The program was finalized in the spring of 2013 and identified $959 million

in additional capital requirements for the Columbia Generating Station from July 2014 through June 2024. Bonneville expects that a large portion of any new capital needs for the project will be funded with bonds issued by Energy Northwest, the debt service of which will be covered by Bonneville under Net Billing Agreements.

Transmission capital expenditures were approximately $463 million, $514 million, and $560 million in Fiscal Years 2010, 2011, and 2012, respectively. Of these amounts, Bonneville's capital expenditures funded by borrowing from the United States Treasury were approximately $305 million, $301 million, and $255 million in Fiscal Years 2010, 2011, and 2012, respectively. Bonneville forecasts that annual transmission capital expenditures will average approximately $610 million per year in Fiscal Years 2013-2015. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

Conservation capital expenditures were approximately $58 million, $162 million, and $80 million, in Fiscal Years 2010, 2011, and 2012, respectively. Bonneville forecasts that conservation capital expenditures will average approximately $81 million per year in Fiscal Years 2013-2015. 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 were approximately $148 million, $201 million, and $214 million in Fiscal Years 2010, 2011, and 2012, respectively Bonneville forecasts that annual Federal System hydroelectric capital expenditures will average approximately $239 million in Fiscal Years 2013-2015.

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 estimates that, absent the use of third party debt and similar funding arrangements, it could reach the ceiling amount of its authority to borrow from the United States Treasury as early as 2017. In view of this possibility, Bonneville worked 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. As a result, Bonneville has developed a capital strategy that incorporates the expected use of third party debt and similar funding arrangements to meet Bonneville's capital needs. Bonneville believes that adherence to the capital strategy will assure, through at least Fiscal Year 2023, that Bonneville will have remaining capacity to borrow from the United States Treasury which is sufficient to meet Bonneville's capital and liquidity needs.

To the extent that Bonneville uses non-Treasury financing sources that are secured by cash payments by Bonneville, such as transmission facility lease-purchase arrangements and electric power conservation or generating resource acquisitions, the related debt service costs are and will be payable on the same parity as payments by Bonneville under the Cowlitz Falls Project Agreements, including with respect to debt service on the 2013 Bonds, in the order in which Bonneville's costs are met. See "—Order in Which Bonneville's Costs Are Met." Some other capital sources for the Federal System are supported by Bonneville through non-cash payment crediting arrangements such as net billing and power prepayment credits. To the extent that these capital sources are achieved through such crediting arrangements, they reduce the cash in the Bonneville Fund that would otherwise be available to make payments under the Cowlitz Falls Project Agreements, including with respect to debt service on the 2013 Bonds.

Energy Northwest 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. 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). As of September 30, 2012, there are approximately $5.94 billion in 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.

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 approximately $3.5 billion for the period of Energy Northwest Fiscal Years (July 1st – June 30th) 2012 – 2024. See also "POWER SERVICES—Columbia Generating Station and Energy Northwest Depleted Uranium Enrichment Program." Aggregate debt service for Project 1 is estimated by Energy Northwest to be approximately $1.7 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 approximately $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 $270.4 million in Energy Northwest Fiscal Year 2012.

Under certain Direct Payment Agreements, Bonneville meets the Net Billed Project costs on a current basis and without the use of net billing; however, under the Direct Payment Agreements, net billing would be re-instituted if Bonneville were to make insufficient payments thereunder. See "—Direct Pay Agreements." Net billing affects the amount of cash that Bonneville would otherwise have available to meet its other costs, including the payments under the Cowlitz Falls Project Agreements, which payments cover debt service on the 2013 Bonds. See "—Order in Which Bonneville's Costs are Met."

Energy Northwest Direct Pay Agreements

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

In reliance on Bonneville's Direct Pay Agreement obligations, the billing statements that Energy Northwest is required to provide to Participants under the Net Billing Agreements show and will show the expected payments from Bonneville under the Direct Pay Agreements as amounts payable from sources other than the Net Billing Agreements. Thus, the amounts to be paid by Participants to Energy Northwest in a Net Billing Agreement Contract Year are and will in the future be reduced to zero, thereby reducing Bonneville's obligation to provide net billing credits to zero as

well. In this manner, Bonneville meets and will meet the costs of the Net Billed Projects on a current basis entirely by means of cash payments from the Bonneville Fund.

The Direct Pay Agreements did not and do not result in the amendment or termination of the Net Billing Agreements or any other agreements of Bonneville with respect to the Net Billed Projects. The Direct Pay Agreements provide that, in the event that Bonneville were to fail to make required payments under the Direct Pay Agreements, Energy Northwest would re-initiate net billing as required under the Net Billing Agreements. In the event that payments under the Direct Pay Agreements were to fall short of meeting Net Billed Project costs or the Direct Payment Agreements were terminated, under the Net Billing Agreements, the Participants would resume making payments directly to Energy Northwest and Bonneville would resume crediting (net billing) amounts otherwise due to Bonneville by the Participants for power and transmission purchases from Bonneville, up to the amount of payments made by the Participants to Energy Northwest. In general, the amount of the Participants' payments subject to net billing is based on the amount of transmission and power purchased from Bonneville and the rates levels charged by Bonneville for such purchases.

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

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for the Corps, Reclamation, and the Fish and Wildlife Service in Fiscal Year 2012 were $184 million, $91 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 approximately $675 million to $802 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 2018. 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."

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 2012 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $886 million in Fiscal Year 2012, approximately $53 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 2013.

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 under the Cowlitz Falls Project Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash payments under the Power Purchase Contract and the Payment Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SECURITY FOR THE 2013 BONDS—Power Purchase Contract," and "—Payment Agreement."

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

Bonneville also has obligations to reduce future amounts receivable from certain power customers that have prepaid for electric power, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—2013 Power Prepayment Program," and from certain transmission customers that have provided lump sum payments to Bonneville for it to construct or install certain transmission facilities necessary to provide transmission service to the customers. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System." The credits for prepaid power will be approximately $30.6 million per year through fiscal year 2028. Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments was $44 million in Fiscal Year 2013 and will be $40 million in Fiscal Year 2014. Bonneville may in the future enter into additional arrangements which could increase the forgoing power and transmission payment credits. The credits have the effect of reducing Bonneville's future cash revenue from the participating customers, and thereby will reduce in the future the amount of cash in the Bonneville Fund that would otherwise be available to meet Bonneville's cash payment obligations, including under the Cowlitz Falls Project 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 2012, approximately $217 million in reserves were derived from Power Services rates and operations and $487 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.

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 2010 through 2012 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.

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

Fiscal Year ending September 30,	**2012**	**2011**	**2010**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities [1]	$1,833,277	$ 1,762,498	$ 1,775,882
Direct Service Industrial Customers	108,628	103,241	80,655
Northwest Investor-Owned Utilities	65,668	154,569	133,678
Sales outside the Northwest Region [2]	443,022	466,493	243,356
Book-outs [3]	(61,972)	(92,198)	(120,803)
Total Sales of Electric Power	2,388,623	2,394,603	2,112,768
Transmission [4]	821,232	775,770	770,504
Fish Credits and other revenues [5]	107,995	114,401	171,859
Total Operating Revenues	3,317,850	3,284,774	3,055,131
Operating Expenses:			
Bonneville O&M [6]	965,419	914,457	847,954
Purchased Power [3]	143,119	177,953	381,468
Corps, Reclamation, and Fish & Wildlife O&M [7]	297,873	280,349	271,502
Non-Federal entities O&M — net billed [8]	283,745	311,948	250,624
Non-Federal entities O&M — non-net billed [9]	46,153	42,788	38,638
Total Operation and Maintenance	1,736,309	1,727,495	1,790,186
Net billed debt service	643,527	608,171	546,987
Non-net billed debt service	16,153	16,801	53,373
Non-Federal Projects Debt Service [10]	659,680	624,972	600,360
Federal Projects Depreciation	389,097	393,502	368,371
Residential Exchange [11]	203,712	184,764	180,453
Total Operating Expenses	2,988,798	2,930,733	2,939,370
Net Operating Revenues	329,052	354,041	115,761
Interest Expense:			
Appropriated Funds	232,364	245,106	257,505
Long-term debt	120,686	135,141	83,608
Capitalization Adjustment [12]	(64,905)	(64,905)	(64,905)
Allowance for funds used during construction	(45,845)	(42,983)	(32,866)
Net Interest Expense [13]	242,300	272,359	243,342
Net Revenues/(Expenses)	$ 86,752	$ 81,682	$ (127,581)
Total Sales — average megawatts (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	10,819	11,042	8,936

(1) This customer group includes Preference Customers (municipalities, public utility districts, and electric cooperatives in the Region) and Federal agencies. This amount reflects refunds to Preference Customers arising from past overpayments of Residential Exchange Program benefits to Regional IOUs. Amounts recorded in Fiscal Year 2012 were $76.5 million (see note 11 below).

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

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for 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 approximately $123.1 million, $85.1 million, and $77.0 million in Fiscal Years 2010, 2011, and 2012, 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 gain of $14.8 million in Fiscal Year 2010, and no gain or loss in Fiscal Years 2011 and 2012, respectively. The gain or loss of zero in Fiscal Years 2011 and 2012 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, and for Bonneville's operation and maintenance, power marketing, and fish and wildlife programs.

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

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

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

(10) Non-Federal Projects Debt Service includes payments by Bonneville for all or a part of the generating capability of, and the related debt service, including interest, for Energy Northwest's 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 Fiscal Year 2012 through Fiscal Year 2028 were established under the 2012 Residential Exchange Program Settlement Agreement, dated July 26, 2011. In Fiscal Year 2012, the Residential Exchange Program payments were $182.1 million. In Fiscal Year 2012, Bonneville also provided refunds in an aggregate amount of $76.5 million to qualifying Preference Customers for overpayments (Refund Amounts) Bonneville made to Regional IOUs for the period July 1, 2001, through September 30, 2011, under the original Residential Exchange Program Settlement Agreements, as thereafter amended and supplemented, that were invalidated by the Ninth Circuit Court in May 2007. Bonneville recognizes a refund for refund amounts recovered from Regional IOUs in the rate setting process and returned to Preference Customers and will do so through Fiscal Year 2019, at which time all overpayments will be fully recovered. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

(12) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing Federal 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 2012

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

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

Transmission Services gross sales increased $51 million, or approximately seven percent, due in part to a $20 million increase in revenues from long-term Point-to-Point service (a type of transmission service that uses a single transmission path between two points) and $20 million due to a rate increase for providing certain power system operating reserves, which is an ancillary service.

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

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

Fiscal Year 2011

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

For Fiscal Year 2011, Power Services and Transmission Services consolidated gross sales increased $255 million, or nine percent, from the prior fiscal year. Power Services gross sales increased $253 million, or eleven percent. The change was primarily due to several key factors. Firm power sales increased $72 million, or four percent, in Fiscal Year 2011 compared to Fiscal Year 2010 due to higher power sales revenue from Preference Customers resulting from an increase in the amount of power sold. 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 fifty nine percent, in Fiscal Year 2011 compared to Fiscal Year 2010 due to much higher stream flows. January 2011 through July 2011 runoff volume at The Dalles Dam was 142 MAF, the fourth highest on record. For the entire Fiscal Year 2011, the Federal System experienced the sixth highest water year on record at 175 MAF, a significant increase from 110 MAF in Fiscal Year 2010 and above the historical average.

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

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

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

Fiscal Year 2010

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

For Fiscal Year 2010, Power Services and Transmission Services consolidated gross sales increased $192 million, or seven percent, from the prior fiscal year. Power Services gross sales increased $143 million, or seven percent. The change was primarily due to several key factors. Regional requirements sales (to Preference Customers, DSIs, and Regional Federal agencies) increased $164 million in Fiscal Year 2010 compared to Fiscal Year 2009, due to higher power rates taking effect during Fiscal Year 2010. Seasonal Surplus (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 at The Dalles Dam. 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 were $186 million, a seven percent increase 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."

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,	**2012**	**2011**	**2010**
Total Operating Revenues	$3,317,850	$3,284,774	$3,055,131
Less: Operating Expense[1]	1,642,148	1,640,415	1,707,561
Net Funds Available for Non-Federal Project Debt Service	1,675,702	1,644,359	1,347,570
Less:			
Non-Federal Project Debt Service[2]	659,680	624,972	600,360
Lease Financing Program[3]	25,451	23,872	20,718
Revenue Available for Treasury	990,571	995,515	726,492
Amount Allocated for Payment to Treasury[8]:			
Corps and Reclamation O&M[4]	297,873	280,349	271,502
Net Interest Expense[5]	242,300	272,359	243,342
Lease Financing Program[3]	(25,451)	(23,872)	(20,718)
Capitalization Adjustment[6]	64,905	64,905	64,905
Allowance for Funds Used During Construction[5] to [7]	28,175	25,022	16,109
Amortization of Principal	393,110	409,528	459,829
Total Amount Allocated for Payment to Treasury[8]	1,000,912	1,028,291	1,034,969
Revenues Available for Other Purposes[9]	(10,341)	(32,776)	(308,477)
Non-Federal Project Debt Service Coverage Ratio[10]	2.4x	2.5x	2.2x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[11]	1.4x	1.4x	1.3x

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

(2) Includes debt service for generating resources acquired by Bonneville under Net Billing Agreements or other capitalized contracts. Non-net billed debt service amounted to $53.4 million, $16.8 million, and $16.2 million for Fiscal Years 2010, 2011 and 2012, respectively.

(3) Includes related debt service amounts with respect to certain transmission facilities that Bonneville is leasing under capitalized lease-purchase agreements. 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 2010, 2011, and 2012. 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 2010, 2011, and 2012 were $864 million, $830 million, and $886 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, 2013

For the six months ended March 31, 2013, sales increased $23 million, or 1 percent, from the comparable period a year earlier, as reported in the Combined Statements of Revenues and Expenses. Transmission Services sales increased $14 million, or 4 percent, primarily due to increased Variable Energy Resource Balancing Service (an ancillary service that provides system stability for generators, such as wind projects, whose output varies on short notice) and long-term, Point-to-Point service. Variable Energy Resource Balancing Service revenue was higher by $7 million due to additional installed wind generation facilities. Point-to-Point long-term sales increased by $3 million. Power Services sales increased $9 million, or 1 percent. Firm power sales decreased by $6 million for the six months ended March 31, 2013, compared to the same period in fiscal year 2012. Preference Customer peak loads were lower as a result of above average temperatures in the fall and winter months. Seasonal surplus (secondary) power sales increased $15 million. The increase in seasonal surplus (secondary) sales was due primarily to higher market prices which offset decreased stream flows year-over-year. United States Treasury credits under section 4h(10)(C) of the Northwest Power Act increased $5 million for the six months ended March 31, 2013, from the comparable period a year earlier. The Fiscal Year 2013 increase was primarily driven by higher power purchases made for fish and wildlife mitigation purposes. Miscellaneous revenues increased $3 million year-over-year, primarily due to increases in Transmission Services reimbursable work, offset by a reduction in energy efficiency revenues.

Operations and maintenance expense increased $59 million, or 7 percent, for the six months ended March 31, 2013, from the comparable period a year earlier. Energy Northwest Columbia Generating Station nuclear power plant costs increased $40 million year-over-year for maintenance and biennial refueling. Federal hydro operations and maintenance increased $10 million, transmission maintenance increased $8 million, transmission and ancillary purchases increased $4 million, and fish and wildlife costs were up $3 million. These costs were offset partially by reduced expenses for transmission operations, transmission engineering, conservation and renewable resources.

Nonfederal projects debt service increased $39 million, or 12 percent, for the six months ended March 31, 2013, from the comparable period a year earlier primarily due to increased scheduled debt payments for Energy Northwest's Project No. 1 and Project No. 3.

Depreciation and amortization expense increased $18 million, or 9 percent, for Fiscal Year 2013 when compared to ear 2012. Transmission and generation plant placed in service, including certain information systems, resulted in increases to depreciation of $9 million and $6 million, respectively. Amortization of conservation and fish and wildlife regulatory assets increased $3 million.

Net interest expense increased $34 million, or 33 percent, for the six months ended March 31, 2013, from the comparable period a year ago. Interest expense increased $11 million, or 7 percent, due to increased borrowing necessary to finance certain Corps' projects and increased lease-financed transmission construction, and to a one-time reduction in Fiscal Year 2012 of costs allocated for recovery in Bonneville's rates in connection with a comparatively small Federal System hydroelectric project owned and operated by the Corps. Allowance for funds used during construction ("AFUDC") decreased $5 million year over year, primarily due to a lower AFUDC rate. Interest income decreased $18 million primarily as the result of a Fiscal Year 2012 accrual for interest income related to outstanding receivables and, to a lesser extent, a lower interest rate earned on balances with United States Treasury.

For further information regarding Fiscal Year 2013 Second Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2013." For information regarding Bonneville's Fiscal Year 2013 financial expectations, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2013 Expectations."

BONNEVILLE LITIGATION

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

Columbia River ESA Litigation

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

In 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.

In September 2009, the Federal agencies filed a "Management Plan" with the court. In the Management Plan, the Federal agencies outlined a more detailed and aggressive plan for implementing the adaptive management provisions of the 2008 Columbia River System Biological Opinion. In May 2010, NOAA Fisheries finalized a "2010 Supplemental Columbia River System Biological Opinion" to supplement the existing 2008 Columbia River System Biological Opinion and to incorporate the Management Plan. In August 2011, the Oregon Federal District Court upheld the 2010 Supplemental Columbia River System Biological Opinion through 2013 since mitigation plans are adequate through that time period. Implementation costs are substantially similar to costs incurred in prior fiscal years. The court has ordered NOAA Fisheries to issue a new or supplemental Columbia River System Biological Opinion by January 1, 2014 for the calendar years 2014 through 2018 and that such Biological Opinion identify specific, verifiable mitigation plans beyond 2013 and provide better scientific support for the conclusion that the related measures will avoid jeopardy than was provided for such period in the 2010 Supplemental Columbia River System Biological Opinion. NOAA Fisheries, the Corps and Reclamation are developing a new supplemental biological opinion in conformance with the court's order and expect to issue the new biological opinion by January 1, 2014. 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 approximately $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 2007-2013, the Federal agencies proposed a spill program similar to the 2006 spill program and obtained court approvals.

See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

DSI Service Litigation

Bonneville's power sales to DSIs have been the subject of litigation since 2000. The only extant litigation is currently pending in the Ninth Circuit Court. The issues in the case pertain to contracts originally intended to provide power sales service by Bonneville to two current DSIs (Alcoa, and Port Townsend Paper) and one former DSI, (Columbia Falls Aluminum Corporation) for portions of the period Fiscal Years 2007–2011. In 2007, two Preference Customers, an association of Preference Customers and an association representing industrial customers of Preference Customers (collectively, the "DSI Service Petitioners") filed legal challenges in the Ninth Circuit Court seeking to set aside Bonneville's entry into the contracts and requesting that the Ninth Circuit Court direct Bonneville to take action to recoup from the DSIs approximately $159 million in amounts paid by Bonneville in lieu of physical power deliveries to the DSIs under the contracts. In 2008, the Ninth Circuit Court partially invalidated the contracts, but denied the DSI Service Petitioners' request for relief. However, the court remanded the recoupment matter to Bonneville for further consideration. On remand, Bonneville considered:

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

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

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

Bonneville's power sales to Port Townsend and Alcoa are now governed by contracts for sale and delivery of power at the IP Rate, in the amounts of 20.5 annual average megawatts and 300 annual average megawatts, respectively, for a term of ten years ending near the end of calendar year 2022. The 90 day period permitted for filing challenges to Bonneville's decisions to enter into such DSI contracts has elapsed without legal challenge. Any future effort to initiate such a challenge would be time-barred.

Tiered Rates Methodology Record of Decision

Several petitioners challenged Bonneville's Tiered Rates Methodology Record of Decision ("Tiered Rates ROD") and Bonneville's Tiered Rates Methodology, both issued November 10, 2008. For a discussion of Tiered Rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services— Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Long-Term Preference Contracts." The petitioners include Clatskanie Peoples Utility District (a Preference Customer), Georgia-Pacific, LLC ("GP") (an industrial customer of Clatskanie), and the Industrial Customers of Northwest Utilities ("ICNU") (an association of industrial customers that purchase power from Preference Customers).

The petitioners challenged Bonneville's determination in the Tiered Rates ROD regarding Bonneville's treatment of "contracted for or committed to" loads, a specialized term under the Northwest Power Act relating to the amount of

electric power a Regional customer may include in its requirements purchases from Bonneville for the loads of the customers' industrial end-use customers. 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. The Ninth Circuit dismissed these petitions as unripe because the BPA rates in question were not yet final. Oral argument was held in July 2012. However, Clatskanie and certain other petitioners have raised similar challenges with respect to the implementation of Tiered Rates in Bonneville's final power rates for Fiscal Years 2012-13.

2010 and 2012 Power Rates Challenges

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

FERC approved the 2010-2011 Rates in August 2010. In early November 2010, certain Regional IOUs, Preference Customers, and a group of industrial customers filed petitions to challenge the 2010-2011 Rates and the decisions Bonneville reached in the 2010 Rates ROD. It is unclear which aspects of the rates and/or ratemaking process are being challenged. These petitions were consolidated with the earlier petitions that challenged the 2010 Rates ROD. These petitions have been stayed pending resolution of litigation over the 2012 REP Settlement. 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 2011, Clatskanie, Georgia Pacific, and ICNU filed petitions for review with the Ninth Circuit Court challenging certain decisions in the 2012 Rates ROD regarding "contracted for or committed to" loads; they alleged those decisions involved non-ratemaking issues that might be subject to the court's jurisdiction prior to FERC's final approval of the Final 2012-2013 Rates. These petitions were consolidated and stayed until FERC's final approval of the Final 2012-2013 Rates. After FERC issued final approval of Bonneville's rates on December 31, 2012, these petitions were again stayed until June 24, 2013. Following FERC's final approval of Bonneville's rates, the same three parties filed new petitions for review in the Ninth Circuit challenging aspects of Bonneville's final rates. Those three petitioners have been consolidated and have also been stayed until June 24, 2013 along with the prior petitions from the same parties.

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.

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

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

In July 2009, Bonneville concluded its rate case in which Bonneville established rates for the 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, certain provisions of the Final 2010-2011 Power Rates relating to the Residential Exchange Program.

In late 2010, most of the litigants in the aforementioned litigation developed a proposed settlement agreement of the outstanding Residential Exchange Program-related issues. 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 proposed 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 proposed settlement (as adopted by Bonneville, the agreement is referred to herein as the "2012 Residential Exchange Program Settlement Agreement").

On August 8, 2011, Bonneville and certain Preference Customers that signed the 2012 Residential Exchange Program Settlement Agreement 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 Agreement rendered such appeals moot. Regional IOUs filed a separate motion to stay related proceedings.

In October of 2011, Alcoa (a DSI) and the Association of Public Agency Customers ("APAC") (an association of end-use consumers that purchase electric power from Preference Customers) filed petitions challenging the 2012 Residential Exchange Program Settlement Agreement and supporting Record of Decision. 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. Briefing on the merits was completed in July, 2012. In December of 2012, Alcoa filed a motion to be dismissed from the litigation, which the court granted in April 2013. APAC is the only remaining petitioner in this case. Oral argument on APAC's petition was held on February 19, 2013. The court has not rendered a decision in this case.

Southern California Edison v. Bonneville Power Administration

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

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

Rates Litigation Generally

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

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

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 State Tax Court. Bonneville and the United States appealed the Oregon Federal District Court decision to the Ninth Circuit Court. 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 also appealed the second Oregon Federal District Court decision to the Ninth Circuit Court. Both appeals to the Ninth Circuit Court were consolidated. On January 2, 2013, the Ninth Circuit Court affirmed both Oregon Federal District Court decisions to dismiss the cases.

On November 30, 2012, the defendants filed a motion for summary judgment in the Oregon Tax Court case. On January 16, 2013, the United States filed its reply to the defendants' motion for summary judgment and a cross-motion for summary judgment. On February 15, 2013, the defendants filed a joint response to the United States' cross-motion for summary judgment and reply brief. The parties are awaiting oral argument. The Oregon Department of Revenue agreed to toll assessment pending final resolution of this matter. Bonneville estimates that the total tax at issue for 2009-2013 is approximately $5,300,000. 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."

On May 29, 2013, the State of Oregon legislature enacted legislation that Bonneville believes finally resolves the litigation and eliminates the current, tolled property tax liability. On June 7, 2013, the Oregon Governor signed the bill into law. The enactment also precludes the future imposition of Oregon real property tax on transmission facilities that are located on property in Oregon and lease-purchased by Bonneville.

Miscellaneous Litigation

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

Report of Independent Auditors

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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2012, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2012 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 26, 2012

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Federal Columbia River Power System
Combined Balance Sheets

As of September 30

(Thousands of Dollars)

	2012	2011
Assets		
Utility plant		
Completed plant	**$ 15,401,287**	$ 14,741,720
Accumulated depreciation	**(5,449,470)**	(5,436,160)
	9,951,817	9,305,560
Construction work in progress	**1,412,134**	1,396,097
Net utility plant	**11,363,951**	10,701,657
Nonfederal generation	**3,318,494**	2,604,078
Current assets		
Cash and cash equivalents	**948,859**	892,125
Short-term investments in U.S. Treasury securities	**242,495**	253,348
Accounts receivable, net of allowance	**86,632**	119,596
Accrued unbilled revenues	**248,769**	207,089
Materials and supplies, at average cost	**99,436**	93,924
Prepaid expenses	**26,060**	29,430
Total current assets	**1,652,251**	1,595,512
Other assets		
Regulatory assets	**7,464,988**	7,812,358
Investments in U.S. Treasury securities	**49,623**	39,129
Nonfederal nuclear decommissioning trusts	**235,598**	198,809
Deferred charges and other	**180,444**	223,736
Total other assets	**7,930,653**	8,274,032
Total assets	**$ 24,265,349**	$ 23,175,279

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)

	2012	2011
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 2,595,940**	$ 2,510,373
Federal appropriations	**4,249,022**	4,324,881
Borrowings from U.S. Treasury	**3,263,040**	2,678,440
Nonfederal debt	**6,370,733**	5,843,046
Total capitalization and long-term liabilities	**16,478,735**	15,356,740
Commitments and contingencies (Note 14)		
Current liabilities		
Federal appropriations	**-**	24,622
Borrowings from U.S. Treasury	**157,800**	265,000
Nonfederal debt	**493,650**	429,545
Accounts payable and other	**554,006**	523,459
Total current liabilities	**1,205,456**	1,242,626
Other liabilities		
Regulatory liabilities	**2,545,370**	2,456,343
IOU exchange benefits	**3,081,053**	3,161,251
Asset retirement obligations	**161,215**	176,212
Deferred credits and other	**793,520**	782,107
Total other liabilities	**6,581,158**	6,575,913
Total capitalization and liabilities	**$ 24,265,349**	$ 23,175,279

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)

	2012	2011	2010
Operating revenues			
Sales	**$ 3,179,592**	$ 3,134,209	$ 2,851,097
Derivative instruments	**-**	-	14,800
U.S. Treasury credits for fish	**76,983**	85,102	123,090
Miscellaneous revenues	**61,275**	65,463	66,144
Total operating revenues	**3,317,850**	3,284,774	3,055,131
Operating expenses			
Operations and maintenance	**1,796,902**	1,734,306	1,589,171
Purchased power	**143,119**	177,953	381,468
Nonfederal projects	**659,680**	624,972	600,360
Depreciation and amortization	**389,097**	393,502	368,371
Total operating expenses	**2,988,798**	2,930,733	2,939,370
Net operating revenues	**329,052**	354,041	115,761
Interest expense and (income)			
Interest expense	**331,732**	352,904	331,255
Allowance for funds used during construction	**(45,845)**	(42,983)	(32,867)
Interest income	**(43,587)**	(37,562)	(55,046)
Net interest expense	**242,300**	272,359	243,342
Net revenues (expenses)	**86,752**	81,682	(127,581)
Accumulated net revenues at October 1	**2,510,373**	2,428,691	2,556,272
Irrigation assistance	**(1,185)**	-	-
Accumulated net revenues at September 30	**$ 2,595,940**	$ 2,510,373	$ 2,428,691

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)

	Accumulated Net Revenues	Federal Appropriations	Borrowings from U.S. Treasury	Nonfederal Debt	Total
Balance at September 30, 2010	$ 2,428,691	$ 4,259,399	$ 2,513,440	$ 6,321,760	$ 15,523,290
Federal appropriations:					
Increase	-	129,632	-	-	129,632
Decrease	-	(39,528)	-	-	(39,528)
Borrowings from U.S. Treasury:					
Increase	-	-	800,000	-	800,000
Decrease	-	-	(370,000)	-	(370,000)
Nonfederal debt:					
Increase	-	-	-	349,108	349,108
Decrease	-	-	-	(398,277)	(398,277)
Net revenues	81,682	-	-	-	81,682
Balance at September 30, 2011	$ 2,510,373	$ 4,349,503	$ 2,943,440	$ 6,272,591	$ 16,075,907
Federal appropriations:					
Increase	**-**	**104,696**	**-**	**-**	**104,696**
Decrease	**-**	**(205,177)**	**-**	**-**	**(205,177)**
Borrowings from U.S. Treasury:					
Increase	**-**	**-**	**806,000**	**-**	**806,000**
Decrease	**-**	**-**	**(328,600)**	**-**	**(328,600)**
Nonfederal debt:					
Increase	**-**	**-**	**-**	**1,023,045**	**1,023,045**
Decrease	**-**	**-**	**-**	**(431,253)**	**(431,253)**
Net revenues	**86,752**	**-**	**-**	**-**	**86,752**
Irrigation assistance	**(1,185)**	**-**	**-**	**-**	**(1,185)**
Balance at September 30, 2012	**$ 2,595,940**	**$ 4,249,022**	**$ 3,420,840**	**$ 6,864,383**	**$ 17,130,185**

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)

	2012	2011	2010
Cash provided by and (used for) operating activities			
Net revenues (expenses)	**$ 86,752**	$ 81,682	$ (127,581)
Non-cash items:			
Depreciation and amortization	**389,097**	393,502	368,371
Amortization of nonfederal projects	**390,266**	306,175	270,525
Unrealized (gain) loss on derivative instruments	**-**	-	(14,800)
Changes in:			
Receivables and unbilled revenues	**(7,564)**	(5,112)	(30,109)
Materials and supplies	**(5,512)**	(8,127)	(8,185)
Prepaid expenses	**3,370**	(3,598)	(1,180)
Accounts payable and other	**35,084**	(50,229)	91,915
Regulatory assets and liabilities	**(162,772)**	(209,173)	(164,775)
Other assets and liabilities	**(80,698)**	(68,134)	(13,813)
Net cash provided by operating activities	**648,023**	436,986	370,368
Cash provided by and (used for) investing activities			
Investment in:			
Utility plant, including AFUDC	**(861,754)**	(787,384)	(683,680)
U.S. Treasury securities:			
Purchases	**(635,000)**	(310,000)	(100,000)
Maturities	**638,767**	163,193	44,683
Deposits to nonfederal nuclear decommissioning trusts	**(9,211)**	(9,616)	(8,753)
Special purpose corporations' trust funds:			
Deposits to	**(202,287)**	(106,260)	(4,646)
Receipts from	**231,994**	66,601	39,780
Net cash used for investing activities	**(837,491)**	(983,466)	(712,616)
Cash provided by and (used for) financing activities			
Federal appropriations:			
Proceeds	**104,696**	129,632	86,470
Repayment	**(164,594)**	(39,528)	(204,829)
Borrowings from U.S. Treasury:			
Proceeds	**806,000**	800,000	638,000
Repayment	**(328,600)**	(370,000)	(255,000)
Nonfederal debt:			
Proceeds	**202,289**	201,963	4,646
Extinguished through refinancing	**-**	(90,000)	-
Repayment	**(364,388)**	(308,277)	(270,525)
Customers:			
Advances for construction	**27,634**	59,806	92,786
Reimbursements to customers	**(35,650)**	(23,662)	(27,648)
Irrigation assistance	**(1,185)**	-	-
Net cash provided by financing activities	**246,202**	359,934	63,900
Net increase and (decrease) in cash and cash equivalents	**56,734**	(186,546)	(278,348)
Cash and cash equivalents at beginning of year	**892,125**	1,078,671	1,357,019
Cash and cash equivalents at end of year	**$ 948,859**	$ 892,125	$ 1,078,671
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 350,581**	$ 375,755	$ 360,813
Significant noncash investing and financing activities:			
Federal appropriations	**$ (40,583)**	$ -	$ (18,431)
Nonfederal debt increase for Energy Northwest	**$ 782,655**	$ 147,145	$ 22,705
Extinguished through refinancing for Energy Northwest	**$ (66,865)**	$ -	$ -
Other nonfederal	**$ 38,101**	$ -	$ -

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination and consolidation of entities

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

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

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

Use of estimates

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

Rates and regulatory authority

BPA establishes separate power and transmission rates in accordance with several statutory directives. Rates proposed by BPA are subject to an extensive formal hearing process, after which they are proposed by BPA and reviewed by FERC. FERC’s review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. 839e(a)(2), and a standard set out by the Energy Policy Act of 1992, 16 U.S.C. 824. Statutory standards include a requirement that rates must be sufficient to ensure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA’s other costs. After final FERC approval, BPA’s rates are subject to review in the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court). Petitions seeking such review must be filed within 90 days of the final FERC approval. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA.

In accordance with authoritative guidance for Regulated Operations, certain costs or credits may be included in rates for recovery or refund over a future period and are recorded as regulatory assets or liabilities. (See Note 3, Effects of Regulation.) Regulatory assets or liabilities are amortized over the periods they are included in rates. Amortization is computed using either the straight-line method or is based upon specific amounts included in

rates each year. Since BPA's rates are not structured to provide a rate of return on rate base assets, regulatory assets are recovered at cost without an additional rate of return.

Utility plant

Utility plant is stated at original cost and includes generation and transmission assets. Generation assets were $8.17 billion and $7.96 billion at Sept. 30, 2012, and 2011, respectively. Transmission assets were $7.23 billion and $6.78 billion, including assets under capital lease agreements of $127.6 million and $43.9 million, at Sept. 30, 2012, and 2011, respectively. The costs of substantial additions, major replacements and substantial betterments are capitalized. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. Maintenance, repairs and replacements of items determined to be less than major units of property are charged to maintenance and operating expense as incurred. When BPA retires utility plant, it charges the original cost and any net proceeds from the disposition to accumulated depreciation.

Depreciation

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated service lives of the various classes of property, which average 75 years. For transmission plant, depreciation of original cost and estimated net cost of removal is computed primarily on the straight-line group life method based on estimated service lives of the various classes of property, which average 48 years. The estimated net cost of removal is included in depreciation. In the event removal costs are expected to exceed salvage proceeds, a reclassification of this negative salvage is made from accumulated depreciation to a regulatory liability. As actual removal costs are incurred, the associated regulatory liability is reduced.

Allowance for funds used during construction

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

FCRPS capitalizes AFUDC at one rate for Corps and Reclamation construction funded by congressional appropriations and at another rate for construction funded substantially by BPA and the NIFCs. The rates for appropriated funds are provided each year to BPA by the U.S. Treasury, whereas the BPA rate is determined based on the weighted-average cost of borrowing for BPA and the NIFCs. The respective rates for appropriated and BPA funds were approximately 0.1 percent and 4.1 percent in fiscal year 2012, 0.3 percent and 4.4 percent in fiscal year 2011, and 0.4 percent and 4.8 percent in fiscal year 2010. The weighted-average AFUDC rates for fiscal years 2012, 2011 and 2010 approximated the BPA rates for these years.

Nonfederal generation

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

Cash and cash equivalents

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

Concentrations of credit risks

General credit risk

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

BPA's accounts receivable are spread across a diverse group of 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 2012, 2011 and 2010, BPA experienced no material 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 balance is not material to the financial statements.

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.

BPA applies 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.

BPA applies 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 approximate 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 12, Risk Management and Derivative Instruments and Note 13, Fair Value Measurements.)

Revenues and net revenues

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

Interest income

Interest income includes earnings on BPA's fund balance with the U.S. Treasury, on investments in market-based special securities and from other sources. BPA earns interest 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 U.S. Treasury 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 and are shown as a component of Operating revenues in the Combined Statements of Revenues and Expenses.

Residential Exchange Program

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

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

In fiscal year 2011, the BPA administrator signed the 2012 Residential Exchange Program Settlement Agreement (Settlement Agreement), resolving disputes related to the REP. The Settlement Agreement provides for fixed "Scheduled Amounts" payable to the IOUs, as well as fixed "Refund Amounts" payable to the COUs. The Settlement Agreement eliminates the Lookback Amounts as of Sept. 30, 2011, and replaces them with the Refund Amounts for amounts overpaid by the COUs. These amounts do not reduce rates but are reflected as credits to qualifying COUs' bills as designated in the Settlement Agreement. BPA utilizes the rates process to reduce the IOUs' benefits and thus reduce the expense in the year it is applied. (See Note 10, Residential Exchange Program.)

RECENT ACCOUNTING PRONOUNCEMENTS

Balance Sheet Offsetting

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

Fair value measurements and disclosures

In 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. BPA adopted this guidance on Oct. 1, 2010, with the exception of that relating to the gross disclosure of purchase, issuance and settlement activity in Level 3, which BPA adopted on Oct. 1, 2011.

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. This guidance will be effective for fiscal year 2013. BPA is evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

SUBSEQUENT EVENTS

FCRPS has performed an evaluation of events and transactions for potential recognition or disclosure through Oct. 26, 2012, which is the date the financial statements were issued.

2. Investments in U.S. Treasury Securities

As of Sept. 30 — thousands of dollars	**2012**		2011	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Short-term	**$ 242,495**	**$ 242,911**	$ 253,348	$ 253,656
Long-term	**49,623**	**49,984**	39,129	40,712
Total	**$ 292,118**	**$ 292,895**	$ 292,477	$ 294,368

BPA participates in the U.S. Treasury’s Federal Investment Program which provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and have 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 2012 and 2011 had a weighted-average yield of 0.4 percent and 0.8 percent, respectively, and maturities of up to two 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 two years from the balance sheet date.

3. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — thousands of dollars	**2012**	2011
REP Scheduled Amounts	**$ 2,993,310**	$ 3,074,870
Terminated nuclear facilities	**2,606,661**	2,986,393
Columbia River Fish Mitigation	**546,604**	469,783
REP Refund Amounts	**500,155**	565,359
Conservation measures	**297,838**	272,924
Fish and wildlife measures	**278,102**	246,480
Legal claims and settlements	**74,419**	50,428
Derivative instruments	**39,049**	27,422
Spacer damper replacement program	**37,775**	21,853
Federal Employees' Compensation Act	**31,352**	31,352
Trojan decommissioning and site restoration	**23,189**	23,506
Terminated hydro facilities	**18,602**	21,740
Capital bond premiums	**9,810**	10,554
Sponsored conservation	**4,783**	8,615
Other	**3,339**	1,079
Total	**$ 7,464,988**	$ 7,812,358

Regulatory assets include the following items:

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

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

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

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

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

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

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

"Derivative instruments" reflect the unrealized losses from BPA's derivative portfolio. (See Note 12, Risk Management and Derivative Instruments.) These amounts are deferred over the corresponding underlying contract delivery months.

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

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

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

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

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

"Sponsored conservation" consists of the nonfederal debt for Conservation and Renewable Energy System (CARES) and City of Tacoma Conservation bonds. This debt was issued to finance conservation programs sponsored by BPA. The assets are amortized over the term of the related outstanding debt.

REGULATORY LIABILITIES

As of Sept. 30 — thousands of dollars	**2012**	2011
Capitalization adjustment	**$ 1,536,891**	$ 1,601,796
REP Refund Amounts to COUs	**500,155**	565,359
Accumulated plant removal costs	**390,622**	201,266
CGS decommissioning and site restoration	**99,182**	51,409
Derivative instruments	**12,141**	30,924
Other	**6,379**	5,589
Total	**$ 2,545,370**	$ 2,456,343

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 2012, 2011 and 2010, respectively. (See Note 6, Federal Appropriations.)

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

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

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

"Derivative instruments" reflect the unrealized gains from BPA's derivative instruments that are marked-to-market in accordance with current authoritative derivative accounting guidance. (See Note 12, Risk Management and Derivative Instruments.) These amounts are deferred over the corresponding underlying contract delivery months.

4. Asset Retirement Obligations

As of Sept. 30 — thousands of dollars	**2012**	2011
Beginning Balance	**$ 176,212**	$ 170,334
Activities:		
Accretion	**8,305**	8,640
Expenditures	**(1,269)**	(2,234)
Revisions	**(22,033)**	(528)
Ending Balance	**$ 161,215**	$ 176,212

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. During fiscal year 2012, the ARO for CGS decreased by $22.0 million primarily due to a revised cost estimate following relicensing of the facility for an additional 20 years. FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO since no future obligation exists to remove these assets.

AROs include the following items as of Sept. 30, 2012:

- CGS decommissioning and site restoration of $121.4 million;
- Trojan decommissioning of $23.2 million;
- Energy Northwest Project Nos. 1 and 4 site restoration of $16.6 million.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — thousands of dollars	**2012**		2011	
	Amortized cost	**Fair value**	Amortized cost	Fair value
Equity index funds	**$ 84,377**	**$ 100,050**	$ 77,097	$ 74,923
U.S. government obligation mutual funds	**72,200**	**74,067**	84,050	86,834
Corporate bond index funds	**57,150**	**61,460**	36,834	37,028
Cash and cash equivalents	**21**	**21**	24	24
Total	**$ 213,748**	**$ 235,598**	$ 198,005	$ 198,809

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. In May 2012, the NRC renewed CGS's operating license for an

additional 20 years and the license now expires in 2043. Trust fund requirements for CGS are based on an NRC decommissioning cost estimate and the license termination date. The trusts are funded and managed by BPA in accordance with the NRC requirements and site certification agreements.

The investment securities in the decommissioning and site restoration trust accounts are classified by BPA as available-for-sale in accordance with accounting guidance related to Investments, Debt and Equity Securities. BPA recognizes the unrealized gains and losses on these investment securities as adjustments to the related regulatory liability, which represents the excess of the amount previously collected through rates over the current ARO balance. (See Note 3, Effects of Regulation.) Payments to the trusts for fiscal years 2012, 2011 and 2010 were approximately $9.2 million, $9.6 million and $8.8 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	**2012**	2011
Special purpose corporations' trust funds	**$ 121,032**	$ 155,301
Settlements receivable	**16,000**	-
Derivative instruments	**12,141**	32,380
Spectrum Relocation fund	**9,608**	15,884
Funding agreements	**7,174**	-
Trust fund and other deposits	**6,290**	11,341
Energy receivable	**4,768**	5,334
Other	**3,431**	3,496
Total	**$ 180,444**	$ 223,736

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.)

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

"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.

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

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

"Trust fund and other deposits" primarily represent funds held in the Conservation and Renewable Energy System (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. In fiscal year 2012, BPA paid maturing federal appropriations for fiscal years 2012 through 2017. All outstanding federal appropriations are due 2018 and thereafter.

The weighted-average interest rate was 6.2 percent and 6.3 percent on outstanding appropriations as of Sept. 30, 2012, and 2011, respectively.

7. Borrowings from U.S. Treasury

BPA is authorized by Congress to issue to the U.S. Treasury and have outstanding at any one time up to $7.70 billion of interest bearing 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, 2012, of the total $3.42 billion of outstanding bonds, none related to NW Power Act expenses and $367.8 million were for conservation and renewable resources investments. At Sept. 30, 2012, $300.0 million of outstanding bonds carried a variable rate of interest. There were no outstanding bonds with variable rates of interest at Sept. 30, 2011. 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 $484.8 million and $462.6 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2012, and 2011, respectively, for similar maturities.

The weighted-average interest rate on outstanding U.S. Treasury borrowings was 3.6 percent and 4.2 percent as of Sept. 30, 2012, and 2011, respectively. At Sept. 30, 2012, the outstanding bonds with a variable rate of interest carried an interest rate of 0.2 percent.

U.S. Treasury borrowings are callable by BPA at a premium or discount, which is calculated based on the current government agency rates for the remaining term to maturity at the time the bond is called.

MATURING BORROWINGS FROM U.S. TREASURY

As of Sept. 30 — thousands of dollars	
2013	$ 157,800
2014	103,000
2015	210,000
2016	30,000
2017	36,400
2018 through 2042	2,883,640
Total	**$ 3,420,840**

8. Nonfederal Financing

PROJECTS FINANCED WITH NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars	**2012**	2011
Nonfederal generation:		
Columbia Generating Station	**$ 3,224,040**	$ 2,487,355
Cowlitz Falls	**104,650**	116,780
Nonfederal generation	**3,328,690**	2,604,135
Terminated nuclear facilities:		
Nuclear Project No. 1	**1,321,060**	1,573,805
Nuclear Project No. 3	**1,395,405**	1,495,480
Terminated nuclear facilities	**2,716,465**	3,069,285
Lease financing program	**668,054**	559,556
Capital leases	**120,449**	-
Sponsored conservation:		
Conservation and Renewable Energy System	**5,870**	11,200
Tacoma	**5,120**	6,675
Sponsored conservation	**10,990**	17,875
Terminated Northern Wasco Hydro Project	**19,735**	21,740
Total	**$ 6,864,383**	$ 6,272,591

Nonfederal generation and terminated nuclear facilities

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

BPA recognizes expenses for these projects based on total project cash funding requirements, which include debt service and operating and maintenance expenses. BPA recognized operating and maintenance expense for these projects of $298.3 million, $328.1 million and $262.6 million in fiscal years 2012, 2011 and 2010, respectively, which is included in Operations and maintenance expense in the accompanying Combined Statements of Revenues and Expenses. Debt service for the projects of $659.7 million, $625.0 million and $600.4 million for fiscal years 2012, 2011 and 2010, respectively, is reported as Nonfederal projects in the accompanying Combined Statements of Revenues and Expenses.

Related assets for operating projects are included in Nonfederal generation. Related assets for terminated nuclear facilities are included in Regulatory assets. (See Note 3, Effects of Regulation.)

The underlying debt for the Energy Northwest obligations (including terminated nuclear facilities and CGS) currently matures through 2044 with interest rates that are fixed between 1.1 percent and 7.1 percent. Energy Northwest debt of $1.24 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2013 and July 2022 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded recorded value by $824.2 million and $672.7 million as of Sept. 30, 2012, and 2011, respectively. The valuations are based on a market input evaluation pricing methodology using a combination of market observable data such as current market trade data, reported bid/ask spreads and institutional bid information. The weighted-average interest rate was 4.6 percent and 5.1 percent for the Energy Northwest outstanding nonfederal debt as of Sept. 30, 2012, and 2011, respectively.

Lease financing program

Under the Lease Financing Program, BPA consolidates six special purpose corporations, collectively referred to as Northwest Infrastructure Financing Corporations (NIFCs), which issue debt to and receive advances from nonfederal sources. The combined NIFCs have issued $119.6 million in bonds and borrowed $548.5 million on lines of credit with various banks as of Sept. 30, 2012. The bonds bear interest at 5.4 percent per annum and mature in 2034. All NIFC bonds outstanding are subject to redemption by the issuing NIFC, in whole or in part, at any date, at the higher of the principal amount of the bonds or the present value of the bonds discounted using the U.S. Treasury rate plus a premium of 12.5 basis points. The lines of credit become due in full at various dates ranging between Jan. 1, 2015, and Jan. 1, 2019.

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

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

The fair value of the combined NIFC bonds and lines of credit exceeded the recorded value by $45.5 million and $45.0 million as of Sept. 30, 2012, and Sept. 30, 2011, respectively. The valuations are based on the discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2012, and 2011, respectively. The weighted-average interest rate on the NIFCs' outstanding debt was 3.6 percent and 4.0 percent as of Sept. 30, 2012, and Sept. 30, 2011, respectively.

Capital leases

Capital leases include BPA's lease agreement with the Port of Morrow for $84.7 million and other capital lease liabilities totaling $35.7 million. In prior years the capital leases were reported under Deferred credits and other, and at the end of fiscal year 2011 total capital leases were $36.8 million.

The capital leases expire on various dates through 2044 and are for transmission facilities and equipment, such as transmission lines and substation equipment. Certain capital lease agreements contain provisions that allow

BPA to purchase the leased assets for a nominal fee or transfer ownership of the leased assets to BPA at the end of the lease term.

Sponsored conservation and terminated hydro

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

MATURING NONFEDERAL DEBT

As of Sept. 30 — thousands of dollars	
2013	$ 492,370
2014	585,735
2015	791,431
2016	809,107
2017	584,195
2018 and thereafter	3,481,096
Total	**$ 6,743,934**

FUTURE MINIMUM LEASE PAYMENTS UNDER CAPITAL LEASES[1]

As of Sept. 30 — thousands of dollars	
2013	$ 8,122
2014	8,029
2015	8,029
2016	8,030
2017	8,030
2018 and thereafter	249,722
Total undiscounted payments	$ 289,962
Less: Executory costs	(33,402)
Less: Amount representing interest	(136,111)
Present value of minimum lease payments	**120,449**
Less: Current portion	(1,280)
Long-term capital lease liability	$ 119,169

[1] Initial or remaining noncancelable lease terms in excess of one year.

9. Variable Interest Entities

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

BPA reviews executed power purchase agreements with counterparties that may be considered VIEs. These VIEs are typically legal entities structured to own and operate specific generating facilities, primarily wind farms. Because of their pricing arrangements, these agreements may provide that BPA absorb commodity price risk of the counterparty entities. BPA does not provide, and does not plan to provide, any additional financial support to these entities beyond what BPA is contractually obligated to pay. BPA has concluded that it does not control the operating and maintenance activities that most significantly impact these entities. Therefore, BPA is not considered the primary beneficiary of these VIEs and does not consolidate any entities because of power purchase agreements.

BPA is the primary beneficiary of the NIFCs, which are considered VIEs, and BPA therefore consolidates these entities into the FCRPS financial statements. The key factor in this determination is BPA's ability to direct the commercial and operating activities of the transmission facilities underlying the lease agreements. Additionally, BPA's lease agreements with the NIFC entities obligate BPA to absorb the operational and commercial risks, and thus potentially significant benefits or losses, associated with the underlying transmission facilities. Under the lease purchase agreements, the NIFCs issue debt to finance the construction of the transmission facilities which are then leased to BPA. The collateral for the debt is the lease payment stream from BPA. The NIFC entities hold legal title to the transmission facilities during the lease term, and BPA 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 include Deferred charges and other assets of $32.3 million and $33.5 million and Nonfederal debt of $668.1 million and $559.6 million as of Sept. 30, 2012, and 2011, respectively. In July 2012, NIFC II recorded a gain of $1.9 million on the sale of a lease.

10. Residential Exchange Program

BACKGROUND

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

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

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 C

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. (See Note 3, Effects of Regulation.)

2008 IOU EXCHANGE BENEFITS

In fiscal year 2008, Interim Agreements were executed to provide certain IOUs with temporary REP benefits for their residential and small farm consumers. These agreements included a provision to true up the amounts advanced with the actual REP benefits for fiscal year 2008. The true up amount for the IOUs was $69.6 million; however, provisions in the agreement provided that true up payments could not be paid until any subsequent legal challenges to BPA's final ROD, if any, are resolved. (See Note 14, Commitments and Contingencies.) As yet, all legal challenges related to this program have not been resolved.

In 2009, BPA reached a settlement with Avista over its disputed deemer balance, which resulted in the amount due to 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 2012, this balance has increased to $87.7 million and is reported as part of the IOU exchange benefits liability of $3.08 billion as of Sept. 30, 2012.

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 BPA administrator to sign the Settlement Agreement on behalf of BPA. In July 2011, the BPA administrator signed the REP-12 Final ROD and the Settlement Agreement.

In 2011, BPA recorded a long-term IOU exchange benefits liability and corresponding Regulatory asset of $3.07 billion associated with the Settlement Agreement. Beginning in fiscal year 2012, under the provisions of the Settlement Agreement the IOUs began to receive Scheduled Amounts starting at $182.1 million annually 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 $2.99 billion at Sept. 30, 2012, 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 as a Regulatory liability of $500.1 million at Sept. 30, 2012, 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 Case. 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 (BP-12 Rate Case).

11. Deferred Credits and Other

As of Sept. 30 — thousands of dollars	**2012**	2011
Generation interconnection agreements	**$ 271,714**	$ 279,048
Customer reimbursable projects	**232,516**	238,317
Third AC Intertie capacity agreements	**99,231**	101,221
Legal claims and settlements	**80,904**	28,500
Derivative instruments	**39,049**	27,422
Fiber optic leasing fees	**32,599**	32,722
Federal Employees' Compensation Act	**31,352**	31,352
Other	**6,155**	7,906
Capital leases	**-**	35,619
Total	**$ 793,520**	$ 782,107

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 cash or 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.

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

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

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

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

"Capital leases" represent BPA's long-term portion of capital lease liabilities that are not part of the Lease Financing Program. During fiscal year 2012, BPA began reporting all capital lease liabilities as a component of Nonfederal debt. (See Note 8, Nonfederal Financing.)

12. Risk Management and Derivative Instruments

BPA is exposed to various forms of market risk including commodity price risk, commodity volumetric risk, interest rate risk, credit risk and event risk. Non-performance risk, which includes credit risk, is described in Note 13, Fair Value Measurements. BPA has formalized risk management processes in place to manage agency risks, including the use of derivative instruments. The following describes BPA's exposure to and management of risks.

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and 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

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

CREDIT RISK

Credit risk relates to the loss that might occur as a result of counterparty non-performance. 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 methodologies, scoring models, publicly available financial information and external ratings from major credit rating agencies to determine appropriate levels of credit for its counterparties.

During fiscal year 2012, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. At Sept. 30, 2012, BPA had $32.6 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 $21.0 million, or 64.5 percent, of the total credit exposure.

INTEREST RATE RISK

BPA has the ability to issue variable rate debt to the U.S. Treasury. As of Sept. 30, 2012, BPA had $300.0 million in outstanding variable rate U.S. Treasury debt at an average interest rate of 0.2 percent. BPA manages the interest rate risk presented by variable rate U.S. Treasury debt by holding an identical amount of variable rate U.S. Treasury security investments with a similar maturity profile. These U.S. Treasury investments earn interest at a variable rate that is correlated, but not identical, to the interest rate paid on U.S. Treasury variable rate debt. (See Note 2, Investments in U.S. Treasury Securities and Note 7, Borrowings from U.S. Treasury.)

DERIVATIVE INSTRUMENTS

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.

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 13, Fair Value Measurements.)

At Sept. 30, 2012, the derivative commodity contracts recorded at fair value totaled 6.8 million MWh (gross basis) with delivery months extending to September 2017. 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	**2012**	2011
Assets		
Derivative instruments [1]		
Commodity contracts, gross	**$ 14,263**	$ 47,140
Less: netting [2]	**(2,122)**	(14,760)
Total, net	**$ 12,141**	$ 32,380
Liabilities		
Derivative instruments [1]		
Commodity contracts, gross	**$ (41,171)**	$ (42,182)
Less: netting [2]	**2,122**	14,760
Total, net	**$ (39,049)**	$ (27,422)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 11, Deferred Credits and Other.)
[2] Netting represents a balance sheet adjustment for same counterparty master netting arrangements.

Derivative instruments unrealized losses of $30.4 million and unrealized gains of $37.4 million were recorded in Regulatory assets and liabilities in the Combined Balance Sheets in fiscal years 2012 and 2011, respectively. Realized gain and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses as the contracts are delivered and settled.

13. 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, 2012, and 2011.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2012 — thousands of dollars

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

As of Sept. 30, 2011 — thousands of dollars

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 sponsored enterprise obligations	—	125,547	—	—	125,547
U.S. government 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)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 5, Deferred Charges and Other and Note 11, Deferred Credits and Other.) See Note 12, Risk Management and Derivative Instruments for more information related to BPA's risk 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	**2012**	2011
Beginning Balance	**$ 24,643**	$ 17,655
Total unrealized gains (losses) included in:		
Regulatory assets and liabilities [1]	**(10,677)**	6,988
Ending Balance	**$ 13,966**	$ 24,643

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

14. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. BPA makes expenditures and incurs other costs for fish and wildlife projects that are consistent with the Northwest Power Act and that are consistent with the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish species are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions (BiOp) prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA. BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp is not fixed or determinable. However, the current estimate of long-term fish and wildlife agreements with a contractual commitment which BPA has entered into is $911.9 million as of Sept. 30, 2012. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — thousands of dollars	
2013	$ [illegible]61
2014	52,549
2015	52,110
2016	60,957
2017	51,393
2018 and thereafter	389,974
Total	**$ 665,944**

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 $665.9 million over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. BPA is required by the Grand Coulee Dam - Third Powerplant Act to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects to the extent the costs have been determined to be beyond the irrigators' ability to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period. Irrigation assistance excludes $40.3 million for Teton Dam which failed prior to completion and for which BPA has no obligation to repay these costs.

FIRM PURCHASE POWER COMMITMENTS

As of Sept. 30 — thousands of dollars		
2013	$	66,441
2014		35,234
2015		17,477
2016		19,026
2017		20,863
2018 and thereafter		44,877
Total	**$**	**203,918**

BPA periodically enters into long-term commitments to purchase power for future delivery. When BPA forecasts a resource shortage based on expected obligations and the historical water record for the Columbia River basin, BPA takes a variety of steps to cover the shortage including entering into power purchase commitments. Additionally, under BPA's current tiered rates structure, BPA's customers may request that BPA meet their power requirements in excess of their share of BPA's generation resources. BPA may meet these requests by entering into power purchase commitments. The above table includes firm purchase power agreements of known costs that are currently in place to assist in meeting expected future obligations under long-term power sales contracts. Included are six contracts for winter purchases through fiscal year 2014 and eight purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal years 2013 and 2015-2019. The expenses associated with the winter purchases for 2012, 2011 and 2010 were $43.4 million, $43.4 million and $43.1 million, respectively. The expense associated with Tier 2 purchases beginning in fiscal year 2012 was $8.5 million. BPA has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as payments are based on the variable amount of future energy generated and there are no minimum payments required.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Pacific Northwest Electric Power Planning and Conservation Act to meet the net firm power load requirements of its customers in the Pacific Northwest. BPA is authorized to help meet its net firm power load through the acquisition of electric conservation measures. BPA offers a portfolio of initiatives and infrastructure support activities to its customers to ensure the conservation targets established in the Northwest Power and Conservation Council's Sixth Power Plan are achieved. These initiatives and activities are often executed via long-term conservation commitments made by BPA to its customers. These commitments are captured through $96.6 million of agreements with utility customers and contractors that provide support in the way of energy efficiency program research, development and implementation. The timing of the payments under these commitments is not fixed or determinable and these agreements will expire at various dates through fiscal year 2015.

1989 LETTER AGREEMENT

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

NUCLEAR INSURANCE

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

Under each insurance policy, BPA could be subject to a retrospective premium assessment in the event that a member insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Liability Insurance policy is $10.3 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 $4.7 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 as discussed below. BPA has recorded a liability of $28.5 million on the basis that all conditions have been met except the final resolution in the California refund proceedings and related litigation which management considers probable. However, interest payable has not been recorded because the amount that will be paid cannot be reasonably estimated. BPA established an offsetting regulatory asset, as the costs will be collected in future rates.

California parties' refund claims

BPA was a party to proceedings at FERC that sought refunds for sales into markets operated by the California Independent System Operator (ISO) and the California Power Exchange (PX) during the California energy crisis of 2000-2001. BPA, along with a number of other governmental utilities, challenged FERC's refund authority over governmental utilities. In BPA v. FERC, 422 F.3d 908 (9th Cir. 2005) the Ninth Circuit Court found that governmental utilities, like BPA, were not subject to FERC's statutory refund authority. As a consequence of the Ninth Circuit Court's decision, three California investor-owned utilities along with the State of California filed breach of contract claims in the United States Court of Federal Claims against BPA. The complaints, filed in

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.

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. In May 2012, the Court of Federal Claims issued an opinion in the trial on liability issues and held that BPA breached its contracts with the California parties by failing to pay refunds for amounts owed in excess of the mitigated market clearing prices during the refund period. Whether the amounts owed include interest is a contested issue. Assuming the amounts owed do include interest, such refund amounts could amount up to approximately $52 million if ultimately determined to be based on the differences between the mitigated market clearing prices and the prices actually transacted during this period. While this ruling does not establish a specific liability in this matter, BPA recorded a liability in this amount. A trial to determine the amount of damages is currently scheduled for June 2013.

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

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 2011. Since the 2012 REP Settlement Agreement (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 respective motions in the Ninth Circuit Court to dismiss pending litigation challenging those decisions. The cost of providing REP benefits will be recovered through future rates. BPA has recorded regulatory assets, a liability and a regulatory liability for the effects of the Settlement Agreement. (See Note 10, Residential Exchange Program.)

Other

The FCRPS may be affected by various other legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. BPA is unable to predict whether the FCRPS will avoid adverse outcomes in these legal proceedings; however, BPA believes that disposition of pending matters will not have a materially adverse effect on the FCRPS' financial position or results of operations for fiscal year 2012.

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

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Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Thousands of dollars)

	As of March 31, 2013	As of September 30, 2012
Assets		
Utility plant		
Completed plant	$ 15,571,489	$ 15,401,287
Accumulated depreciation	(5,587,120)	(5,449,470)
	9,984,369	9,951,817
Construction work in progress	1,575,431	1,412,134
Net utility plant	11,559,800	11,363,951
Nonfederal generation	3,294,841	3,318,494
Current assets		
Cash and cash equivalents	1,420,918	948,859
Short-term investments in U.S. Treasury securities	493,515	242,495
Accounts receivable, net of allowance	39,016	86,632
Accrued unbilled revenues	297,852	248,769
Materials and supplies, at average cost	108,762	99,436
Prepaid expenses	44,212	26,060
Total current assets	2,404,275	1,652,251
Other assets		
Regulatory assets	7,156,000	7,464,988
Investments in U.S. Treasury securities	4,910	49,623
Nonfederal nuclear decommissioning trusts	248,967	235,598
Deferred charges and other	159,572	180,444
Total other assets	7,569,449	7,930,653
Total assets	$ 24,828,365	$ 24,265,349
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	$ 2,586,330	$ 2,595,940
Federal appropriations	4,289,889	4,249,022
Borrowings from U.S. Treasury	3,518,040	3,263,040
Nonfederal debt	6,744,636	6,370,733
Total capitalization and long-term liabilities	17,138,895	16,478,735
Commitments and contingencies (See Note 14 to 2012 Audited Financial Statements)		
Current liabilities		
Borrowings from U.S. Treasury	182,800	157,800
Nonfederal debt	509,135	493,650
Accounts payable and other	560,927	554,006
Total current liabilities	1,252,862	1,205,456
Other liabilities		
Regulatory liabilities	2,490,799	2,545,370
IOU exchange benefits	3,026,110	3,081,053
Asset retirement obligations	164,582	161,215
Deferred credits and other	755,117	793,520
Total other liabilities	6,436,608	6,581,158
Total capitalization and liabilities	$ 24,828,365	$ 24,265,349

This agency-approved financial information was made publicly available by BPA on 4-26-2013.

Federal Columbia River Power System

Combined Statements of Revenues and Expenses (Unaudited)

(Thousands of dollars)

	Three Months Ended March 31,		Fiscal Year-to-Date Ended March 31,	
	2013	2012	**2013**	2012
Operating revenues				
Sales	**$ 851,549**	$ 837,249	**$ 1,644,709**	$ 1,621,465
U.S. Treasury credits for fish	**21,217**	21,382	**46,622**	41,724
Miscellaneous revenues	**18,770**	20,744	**37,547**	34,376
Total operating revenues	**891,536**	879,375	**1,728,878**	1,697,565
Operating expenses				
Operations and maintenance	**472,560**	447,154	**923,149**	863,868
Purchased power	**67,089**	61,567	**107,221**	106,182
Nonfederal projects	**179,981**	158,707	**359,987**	320,658
Depreciation and amortization	**106,556**	94,532	**210,446**	192,363
Total operating expenses	**826,186**	761,960	**1,600,803**	1,483,071
Net operating revenues	**65,350**	117,415	**128,075**	214,494
Interest expense and (income)				
Interest expense	**85,040**	72,088	**169,503**	158,351
Allowance for funds used during construction	**(10,071)**	(13,496)	**(21,881)**	(26,818)
Interest income	**(5,285)**	(22,722)	**(9,937)**	(27,811)
Net interest expense	**69,684**	35,870	**137,685**	103,722
Net (expenses) revenues	**$ (4,334)**	$ 81,545	**$ (9,610)**	$ 110,772

This agency-approved financial information was made publicly available by BPA on 4-26-2013.

APPENDIX C

SUMMARY OF THE RESOLUTION

The following is a summary of certain provisions of the Resolution, is not to be considered a full statement thereof and is qualified by reference to the complete Resolution.

Certain Definitions Used in the Resolution

"Accreted Value" means with respect to any Capital Appreciation Bonds (a) as of any Valuation Date, the amount set forth for such date in any Supplemental Resolution authorizing such Capital Appreciation Bonds and (b) as of any date other than a Valuation Date, the sum of (i) the Accreted Value on the preceding Valuation Date and (ii) the product of (1) a fraction, the numerator of which is the number of days having elapsed from the preceding Valuation Date and the denominator of which is the number of days from such preceding Valuation Date to the next succeeding Valuation Date, calculated based on the assumption that Accreted Value accrues during any semiannual period in equal daily amounts on the basis of a year of 12 30-day months, times (2) the difference between the Accreted Values for such Valuation Dates.

"Annual Debt Service" for any Fiscal Year means the sum of the amounts required to be paid in such Fiscal Year to pay:

(a) the interest due in such Fiscal Year on all outstanding Bonds, excluding interest to be paid from the proceeds of sale of Bonds or other debt; and

(b) the principal of all outstanding Serial Bonds due in such Fiscal Year, including the Sinking Fund Requirement, if any, for such Fiscal Year; and

(c) amounts required to pay premiums for redeeming Bonds prior to their scheduled maturity; and

(d) any regularly scheduled Payments, adjusted by any regularly Reciprocal Payments, during such Fiscal Year.

For purposes of this definition, the principal and interest portions of the Accreted Value of Capital Appreciation Bonds and the Appreciated Value of Deferred Income Bonds becoming due at maturity or by virtue of a Sinking Fund Requirement shall be included in the calculations of accrued and unpaid and accruing interest or principal in such manner and during such period of time as is specified in any Supplemental Resolution authorizing such Capital Appreciation Bonds or Deferred Income Bonds. For the purpose of calculating the principal and interest on Tender Option Bonds in any Fiscal Year, such Bonds shall be assumed to mature on the stated maturity date or, in the case of Term Bonds, on the mandatory redemption date, if any, thereof.

"Appreciated Value" means with respect to any Deferred Income Bonds, (A) (1) as of any Valuation Date, the amount set forth for such date in any Supplemental Resolution authorizing such Deferred Income Bonds and (2) as of any date other than a Valuation Date, the sum of (a) the Appreciated Value on the preceding Valuation Date and (b) the product of (i) a fraction, the numerator of which is the number of days having elapsed from the preceding Valuation Date and the denominator of which is the number of days from such preceding Valuation Date to the next succeeding Valuation Date calculated based on the assumption that Appreciated Value accrues during any semiannual period in equal daily amounts on the basis of a year of 12 30-day months, times (ii) the difference between the Appreciated Values for such Valuation Dates, and (B) as of any date of computation on and after the Interest Commencement Date, the Appreciated Value on the Interest Commencement Date.

"Board" means the Board of Commissioners of the District, as duly and regularly constituted from time to time.

"Bonneville" means the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration.

"Capital Appreciation Bonds" means any Bonds hereafter issued as to which interest is payable only at the maturity or prior redemption of such Bonds. For the purposes of (i) receiving payment of the redemption price, if any, of a Capital Appreciation Bond that is redeemed prior to maturity, or (ii) computing the principal amount of Bonds held by the owner of a Capital Appreciation Bond in giving to the District or the Paying Agent any notice, consent, request, or demand pursuant to the Resolution for any purpose, the principal amount of a Capital Appreciation Bond shall be deemed to be its Accreted Value.

"Certified Public Accountant" means an independent certified public accountant (or firm of certified public accountants) selected by the District and having a favorable national reputation.

"Closing" means the delivery of any Bonds to, and payment of the purchase price therefor by, the initial purchasers of any Bonds.

"Code" means the Internal Revenue Code of 1986, as amended, together with corresponding and applicable final, temporary or proposed regulations and revenue rulings issued or amended with respect thereto by the United States Treasury Department of the Internal Revenue Service, to the extent applicable to the Bonds.

"Commission" means the Securities and Exchange Commission.

"Cowlitz Falls Agreements" means the Power Purchase Contract and the Payment Agreement.

"Cowlitz Falls Bonds" or "Bonds" means the Cowlitz Falls Project Revenue Bonds of the District authorized to be issued pursuant to the Resolution.

"Cowlitz Falls Project" or "Project" means the separate system of the District as described in FERC License No. 2833, including amendments and revisions now or hereafter approved by FERC, consisting of the electric utility properties and assets, real and personal, tangible and intangible, of the Cowlitz Falls Hydroelectric Project of the District, as created by the Original Resolution, including a dam, spillway, powerhouse, reservoir, transmission and electrical facilities, operations and maintenance facilities, land, and the facilities and programs for wildlife, recreation, debris and sediment control, and other mitigation, and all additions, betterments, renewals, replacements and repairs, improvements to and extensions of such Project, but shall not include the Electric System (including the transmission line from the Glenoma substation to the Mossyrock switchyard) or any other properties, rights or assets, real or personal, tangible or intangible, that hereafter may be purchased, constructed or otherwise acquired by the District as a system that is declared by the Board at the time of financing thereof to be separate from the Cowlitz Falls Project, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire or expand such separate system or otherwise may be pledged to the payment of the bonds of another such separate system of the District.

"Cowlitz Falls Project Power Costs" or "Project Power Costs" means with respect to each month an amount equal to all costs attributable to the Cowlitz Falls Project, to the extent not payable from the proceeds of Bonds or other sources (including income and investment of such proceeds), resulting from the ownership, operation, maintenance of, and repairs, renewals, replacements, additions, improvements, betterments and modifications of the Cowlitz Falls Project, including, without limitation, the following items of cost:

(a) O & M Costs;

(b) Other Renewals and Replacements Costs;

(c) An amount equal to the sum of the following:

(i) All amounts required to be paid into the Interest Account, and the Serial Bond Principal and Term Bond Principal Accounts and amounts, if any, required to be paid into the Reserve Account in the Bond Fund during such month;

(ii) Any amount the District may be required during such month to deposit into any Junior Lien Fund or Account;

(iii) Any amount required to be paid or deposited during such month into the Reserve and Contingency Account in the Revenue Fund or any other fund or account under the Resolution;

(iv) Any amount that the District may be required during such month to pay for the prevention or correction of any unusual loss or damage or for renewals, replacements, repairs, additions, improvements, betterments, and extensions that are necessary or prudent to keep the Cowlitz Falls Project in good operating condition, to improve the operation thereof or to prevent a loss of Cowlitz Falls Revenues therefrom, but in each case only to the extent that funds for such payment are not available to the District from any funds or accounts established under the Resolution for such purposes or funds for such payment are not provided by the issuance of Bonds or other obligations of the District; and

(v) All other charges or obligations of the Project against the Cowlitz Falls Revenues of whatever nature and whether now or hereafter imposed by the Resolution, by law or by contract.

"Cowlitz Falls Revenues" or "Revenues" means all income, revenues, receipts and payments derived by the District in connection with the Cowlitz Falls Project, including with respect to Bonds the debt service of which is to be paid in part or in whole by Bonneville under the Cowlitz Falls Agreements, payments received pursuant to the Power Purchase Contract, and including with respect to all Bonds the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Cowlitz Falls Project and together with the investment income earned on moneys held in any fund or account of the District, including any bond redemption funds and the accounts therein, in connection with the Cowlitz Falls Project, exclusive of insurance proceeds and income derived from investments irrevocably pledged to the defeasance of any specific revenue bonds of the District, such as bonds heretofore or hereafter refunded, or any Bonds defeased pursuant to the Resolution or other bonds defeased, or the payment of which is provided for, under any similar provision of any other bond resolution of the District, and exclusive of payments under the Payment Agreement and moneys in any fund or account hereafter created for the purpose of complying with the rebate provisions of Section 148 of the Code. "Cowlitz Falls Revenues" shall not include any income derived by the District through the ownership and operation of the Electric System or any other generation, transmission or distribution facilities that may hereafter be purchased, constructed or otherwise acquired by the District as a separate system.

"Deferred Income Bonds" means any Cowlitz Falls Bonds issued under any Supplemental Resolution as to which accruing interest is not paid prior to the Interest Commencement Date specified in such resolution and the Appreciated Value for such Bonds is compounded semiannually on the Valuation Date for such Deferred Income Bonds.

"Derivative Facility" means a letter of credit, an insurance policy, a surety bond or other credit enhancement device, given, issued or posted as security for the District's obligations under one or more Derivative Products.

"Derivative Payment Date" means any date specified in the Derivative Product on which a District Payment is due and payable under the Derivative Product.

"Derivative Product" means a written contract or agreement between the District and a third party that has (or whose obligations are unconditionally guaranteed by a party that has) as of the date of the Derivative Product at least an investment grade rating from a rating agency (the "Reciprocal Payor"), which provides that the District's obligations thereunder will be conditioned on the performance by the Reciprocal Payor of its obligations under the agreement; and

(1) under which the District is obligated to pay, on one or more scheduled and specified Derivative Payment Dates, the District Payments in exchange for the Reciprocal Payor's obligation to pay or to cause to be paid to the District, on scheduled and specified Derivative Payment Dates, the Reciprocal Payments;

(2) for which the District's obligations to make the District Payments may be secured by a pledge of and lien on Cowlitz Falls Revenues on an equal and ratable basis with the outstanding Bonds;

(3) under which Reciprocal Payments are to be made directly into the Bond Fund;

(4) for which the District Payments are either specified to be one or more fixed amounts or are determined as provided by the Derivative Product; and

(5) for which the Reciprocal Payments are either specified to be one or more fixed amounts or are determined as set forth in the Derivative Product.

"District Payment" means any payment designated as such by resolution and required to be made by or on behalf of the District under a Derivative Product and which is determined according to a formula set forth in the Derivative Product.

"DTC" means The Depository Trust Company of New York, as depository for the 2013 Bonds, or any successor or substitute depository for the 2013 Bonds.

"Electric System" means the electric utility properties, rights and assets, real and personal, tangible and intangible, now owned and operated by the District and used or useful in the generation, transmission, distribution and sale of electric energy and the business incidental thereto, and all properties, rights and assets, real and personal, tangible and intangible, hereafter constructed or acquired by the District as additions, betterments, improvements or extensions to said electric utility properties, rights and assets, but shall not include the Cowlitz Falls Project or any other generating, transmission and distribution facilities which hereafter may be acquired or constructed by the District as a utility system that is declared by the Board, at the time of financing thereof, to be separate from the Electric System, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire or expand such separate utility system or are otherwise pledged to the payment of the bonds of another such separate utility system of the District other than the Electric System. The Board may, by resolution, elect to combine with and include as a part of the Electric System any other separate utility system of the District, provided that full provision for the payment of any outstanding indebtedness of such separate system shall first be made or such indebtedness shall be refunded or the combined system complies with all covenants of all bond resolutions of the Electric System and such separate system.

"Electric System Bonds" means all bonds issued by the Electric System and which are secured by Electric System Revenues.

"Electric System Operating Expenses" means the District's expenses for operation of the Electric System and routine repairs, renewals, and replacements of the Electric System as more specifically defined in any Electric System resolution, exclusive of the expenses for operation and repairs, renewals and replacements of the Cowlitz Falls Project.

"Electric System Revenues" means income, receipts and revenues received by the District from the sale of electric energy through the ownership or operation of the Electric System and all other commodities, services and facilities sold, furnished or supplied by the District through the ownership or operation of the Electric System, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Electric System, and together with the investment income earned on money held in any fund or account of the District, including any bond redemption funds and the accounts therein, in connection with the ownership and operation of the Electric System (but exclusive of income derived from investments irrevocably pledged to the payment of any specific revenue bonds of the District, such as bonds heretofore or hereafter refunded, or any Electric System Bonds defeased).

"FERC License" means the license (FERC License No. 2833) issued by the Federal Energy Regulatory Commission (FERC), or its successor, to the District on June 30, 1986, and any extensions, renewals, and amendments thereof, which permits the District to construct and operate the Cowlitz Falls Project.

"FERC Uniform System of Accounts" means the system of accounts prescribed by the Federal Energy Regulatory Commission (or its successor in function) for public utilities and licensees, as the same may be amended, at 18 C.F.R. 101, et seq.

"First Supplemental Resolution" means Resolution No. 2612 of the District, adopted May 13, 2013.

"Fiscal Year" means the Fiscal Year used by the District at any time. At the time of the adoption of the Resolution, the Fiscal Year is the 12-month period beginning January 1 of each year.

"Government Obligations" means those obligations as defined in RCW 39.53, as amended.

"Interest Commencement Date" means, with respect to any particular Deferred Income Bonds, the date specified in any Supplemental Resolution authorizing such Bonds (which date must be prior to the maturity date for such Bonds) after which interest accruing on such Bonds shall be payable periodically, with the first such payment date being the applicable interest payment date immediately succeeding such Interest Commencement Date.

"Junior Lien Fund or Account" means any special fund or account created to pay or secure the payment of the principal of and interest on any revenue bonds, warrants or other revenue obligations of the District having a lien upon Cowlitz Falls Revenues and money in the Revenue Fund and accounts therein junior and inferior to the lien thereon for the payment of the principal of and interest on the Bonds, exclusive of funds set aside for the defeasance of any such junior lien obligations.

"Letter of Representations" means the Blanket Letter of Representations from the District to The Depository Trust Company.

"Maximum Interest Rate" means, with respect to any particular Variable Interest Rate Bond, a numerical rate of interest, which shall be set forth in any Supplemental Resolution authorizing such Bond, that shall be the maximum rate of interest such Bond may at any time bear.

"MSRB" means the Municipal Securities Rulemaking Board.

"Operating Year" means any consecutive 12-month period during the Term of the Cowlitz Falls Agreements which commences at 2400 hours, September 30, and ends at 2400 hours the following September 30.

"Operation and Maintenance Costs" or "O & M Costs" means those expenses for operation and maintenance of the Cowlitz Falls Project and routine repairs, renewals of and replacements to the Cowlitz Falls Project, including payments into working capital reserves in the Revenue Fund for items of O & M Costs the payment of which is not immediately required, and shall include, without limiting the generality of the foregoing, operation and maintenance expenses; rents; costs of spare parts; recreation and Cowlitz Falls Project mitigation costs that are not capitalized; administrative and general expenses and insurance costs allocable to the Cowlitz Falls Project; transmission wheeling costs incurred to integrate Project output; engineering expenses; legal fees, Trustee fees, Paying Agent fees, Registrar fees, letter of credit fees, and financial advisor expenses; labor costs and associated taxes and benefits; insurance premiums; any amounts required to be rebated to the federal government pursuant to Section 148 of the Code; and any taxes, assessments, payments in lieu of taxes or other lawful governmental charges, all to the extent properly allocable to the Cowlitz Falls Project under generally accepted accounting principles. Operation and Maintenance Costs shall not include any costs or expenses for new construction that is capitalized, interest, amortization or any allowance for depreciation. During the Term of the Cowlitz Falls Agreements, no cost shall be recognized as an O & M Cost which is not or would not be an O & M Cost under the Power Purchase Contract.

"Original Resolution" means Resolution No. 1847 of the District.

"Other Renewals and Replacements" means actions or items which are not included in O & M Costs that are required by the Cowlitz Falls Project to repair loss or damage, make repairs, renewals and replacements, make additions, betterments, improvements and extensions, comply with regulatory requirements, and to keep the Cowlitz Falls Project in good operating condition.

"Other Renewal and Replacement Costs" means costs incurred for any Other Renewals and Replacements for the Project.

"Outstanding" means Cowlitz Falls Bonds the principal of and interest on which has not been paid under the Resolution and which have not been defeased pursuant to the Resolution.

"Paying Agent" initially means the Trustee, and the designated fiscal agencies of the State of Washington or any bank or banks subsequently designated a paying agent by the District.

"Payment Agreement" means the Payment Agreement between Bonneville and U.S. Bank, National Association, as Trustee.

"Permitted Investments" means any investments or investment agreements which the District is permitted to make under the laws of the State of Washington, as amended from time to time.

"Power Purchase Contract" means the contract executed January 28, 1991 and restated as of May 23, 1991 between the District and Bonneville pursuant to which the District has agreed to sell and Bonneville has agreed to purchase the output of the Cowlitz Falls Project and Bonneville has agreed to pay Cowlitz Falls Project Power Costs.

"Qualified Insurance" means any municipal bond insurance policy or surety bond issued by any insurance company licensed to conduct an insurance business in any state of the United States (or by a service corporation acting on behalf of one or more such insurance companies) which insurance company or companies, as of the time of issuance of such policy or surety bond, are rated in one of the two highest rating categories by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc. or their comparably recognized business successors, or in the event each of such rating agencies rates such institution, by each of them.

"Qualified Letter of Credit" means any letter of credit issued by a bank or financial institution for the account of the District on behalf of the owners of the Bonds or any series of Bonds, which bank or other financial institution issuing the letter of credit maintains an office, agency or branch in the United States and as of the time of issuance of such letter of credit is currently rated in one of the three highest rating categories by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc. or their comparably recognized business successors, or in the event each of such rating agencies rates such institution, by each of them.

"Reciprocal Payment" means any payment, designated as such by resolution, to be made to, or for the benefit of, the District under a Derivative Product by the Reciprocal Payor.

"Reciprocal Payor" means a party to a Derivative Product that is obligated to make one or more Reciprocal Payments thereunder.

"Record Date" for any series of Bonds means the record date or dates established in the Supplemental Resolution providing for the issuance of such series of Bonds.

"Refunded Municipals" means pre-refunded municipal obligations meeting the following conditions: (i) the obligations are not callable prior to maturity or the Trustee has been given irrevocable instructions concerning their call and redemption and the issuer has covenanted not to redeem such bonds other than as set forth in such instructions; (ii) the obligations are secured by cash or Governmental Obligations which may be applied only to interest, principal, and premium payments of such obligations; (iii) the obligations are rated in the highest rating category by Moody's Investors Service or Standard & Poor's Ratings Services, a Division of the McGraw-Hill Companies, Inc., or in the event each of such rating agencies has rated such obligations, by each of them; (iv) the principal and interest of the Governmental Obligations (plus any cash securing such obligations) are sufficient to meet the liabilities of the obligations, which sufficiency has been verified by a Certified Public Accountant; (v) the Government Obligations serving as security for the obligations are held by an escrow agent or a Trustee; and (vi) the Government Obligations are not available to satisfy any other claims, including those against the trustee or escrow agent.

"Refunding Bonds" means Bonds issued for the purpose of refunding Bonds of any prior series of Bonds or for satisfying any reimbursement obligation made pursuant to the Resolution.

"Registered Owner" means the person in whose name a 2013 Bond is registered on the Bond Register. For so long as the District utilizes the book-entry only system for the 2013 Bonds, DTC shall be deemed to be the Registered Owner.

"Registrar" means the registrar and authenticating agent appointed pursuant to the Resolution, its successor or successors and any other entity that may at any time be substituted in its place pursuant to the Resolution.

"Reserve Account Requirement" means for each series of Bonds an amount, if any, determined when each series of Bonds is issued. For all Bonds outstanding, the Reserve Account Requirement is the sum of the Reserve Account Requirements for all series of Bonds; provided, that the Reserve Account Requirement for the 2003 Bonds and the 2013 Bonds shall be zero.

"Resolution" means the 2003 Resolution and, unless the context clearly indicates otherwise, includes the First Supplemental Resolution and all other Supplemental Resolutions.

"Serial Bonds" means Bonds falling due by their terms in specified years for which no mandatory sinking fund payments are required.

"Sinking Fund Requirement" means, for any Fiscal Year, the principal amount and premium, if any, of Term Bonds required to be purchased, redeemed or paid at maturity or paid into any sinking fund account for such Fiscal Year as established by the Supplemental Resolution authorizing the issuance of such Term Bonds.

"Supplemental Resolution" means any resolution adopted by the Board pursuant to and in compliance with the provisions of the Resolution providing for the issuance of Bonds, and shall also mean any other resolution adopted by the Board pursuant to and in compliance with the provisions of the Resolution amending or supplementing the provisions of the Resolution as originally adopted or as theretofore amended or supplemented.

"Tender Option Bonds" means Cowlitz Falls Bonds that the owner may at its option, or is required to, demand payment of the principal and accrued interest thereof or the purchase of such Bonds by or on behalf of the District in advance of the otherwise scheduled dates for the payment of principal and interest thereon.

"Term Bonds" means Bonds of any principal maturity that are subject to mandatory redemption or for which mandatory sinking fund payments are required.

"Term of the Cowlitz Falls Agreements" means the later of the end of the term of the Power Purchase Contract or the Payment Agreement.

"Treasurer" means the Treasurer of the District as designated, from time to time, by resolution of the Board.

"2003 Resolution" means Resolution No. 2245 of the District, adopted June 19, 2003.

"Valuation Date" means (i) with respect to any Capital Appreciation Bonds the date or dates set forth in any Supplemental Resolution authorizing such Bonds on which specific Accreted Values are assigned to the Capital Appreciation Bonds, and (ii) with respect to any Deferred Income Bonds the date or dates prior to the Interest Commencement Date set forth in any Supplemental Resolution authorizing such Bonds on which specific Appreciated Values are assigned to the Deferred Income Bonds.

"Variable Interest Rate" means a variable interest rate or rates to be borne by a series of Cowlitz Falls Bonds or any one or more maturities within a series of Cowlitz Falls Bonds. The method of computing such variable interest rate shall be specified in the Supplemental Resolution authorizing such series of Bonds. Such variable interest rate shall be subject to a Maximum Interest Rate and there may be an initial rate specified, in each

case as provided in such Supplemental Resolution, or a stated interest rate that may be changed from time to time as provided in the Supplemental Resolution. Such Supplemental Resolution shall also specify either (i) the particular period or periods of time or manner of determining such period or periods of time for which each such variable interest rate shall remain in effect or (ii) the time or times upon which any change in such variable interest rate shall become effective and shall specify the frequency and method of payment of Variable Interest Rate Bonds.

"Variable Interest Rate Bonds" for any period of time means Cowlitz Falls Bonds which during such period bear a Variable Interest Rate, provided that Bonds the interest rate on which shall have been fixed for the remainder of the term thereof shall no longer be Variable Interest Rate Bonds.

Funds and Accounts

1. Revenue Fund. The District has pledged to pay all Cowlitz Falls Revenues into the Revenue Fund except as specifically provided in the Resolution. The Revenue Fund consists of the General Account and the Reserve and Contingency Account. The Cowlitz Falls Revenues paid into the Revenue Fund shall first be credited to the General Account. The Cowlitz Falls Revenues in the Revenue Fund and the Bond Fund shall be applied as specified under "SECURITY FOR THE 2013 BONDS – Flow of Funds" in this Official Statement.

There shall be deposited into the Reserve and Contingency Account such funds as the Board deems appropriate to make up any deficiencies in the Reserve Account and the Bond Fund and for other costs of the Project.

2. Bond Fund. Bonneville has agreed in the Cowlitz Falls Agreements to make payments directly to the Trustee for deposit as follows:

(a) Into the Interest Account, on or prior to each interest payment date, the amount equal to the installment of interest next falling due on all Bonds.

(b) Into the Serial Bond Principal Account, on or prior to each date upon which an installment of principal on Serial Bonds falls due, the amount equal to the installment of principal next falling due on the Serial Bonds.

(c) Into the Term Bond Principal Account, on or prior to each date on which a Sinking Fund Requirement falls due, the amount equal to the Sinking Fund Requirements next falling due on all Term Bonds.

Money in the Bond Fund shall be invested in Permitted Investments.

3. Reserve Account. The Reserve Account is established as a separate account in the Bond Fund in order to provide a reserve for the principal, premium, if any, and interest on the Bonds. A separate Reserve Account may be established for a series of Bonds. There is no Reserve Account funding requirement for the 2003 Bonds or the 2013 Bonds.

Additional Bonds and Derivative Products

1. Bonds. Additional Bonds may be issued upon the conditions set forth under the heading "SECURITY FOR THE 2013 BONDS – Additional Bonds."

The District may contract with any entity providing a Qualified Letter of Credit or Qualified Insurance for the Reserve Account that the District's reimbursement obligation to such entity ranks on a parity of lien with the 2013 Bonds, but only if, for as long as any 2013 Bonds remain outstanding, the Power Purchase Contract treats any such obligation as a Project Power Cost or if such reimbursement obligation is payable under the Payment Agreement.

2. Junior Lien Bonds. The District may issue bonds, notes, certificates or other evidences of indebtedness relating to the Project payable from Cowlitz Falls Revenues subordinate to the payments required to be made from the Revenue Fund into the Bond Fund for the 2013 Bonds.

3. Electric System and Other System Bonds. The District may issue bonds payable from Electric System Revenues. The District also may issue bonds payable from revenues of any other separate system.

4. Derivative Products. The District may enter into a Derivative Product on a parity with the Bonds as long as the Derivative Product satisfies the requirements for Additional Bonds described under the heading "SECURITY FOR THE 2013 BONDS – Additional Bonds."

Defeasance of Bonds

The District may or, during the term of the Power Purchase Agreement upon the direction of Bonneville and the provision of sufficient funds or securities as described in the Resolution by Bonneville, shall set aside, together with other moneys legally available therefor, with a trustee or escrow agent in a special account pledged to the payment of all or a portion of the 2013 Bonds, cash, non-callable Government Obligations and/or Refunded Municipals, if permitted by law, sufficient in amount, together with the earnings thereon, to provide funds to pay when due the interest on such 2013 Bonds and to redeem or retire such Bonds at or prior to maturity (as determined by the District) in accordance with their terms. In such event no further payment need be made into the Bond Fund for the payment of the principal of, premium, if any, and interest on the 2013 Bonds so provided for and such Bonds shall cease to be entitled to any lien, benefit or security of the Resolution except the right to receive payment from such special account, and such Bonds shall not be deemed to be outstanding for any purpose of the Resolution or the Supplemental Resolution authorizing their issuance. The District shall obtain an opinion of Bond Counsel to the effect set forth in the preceding sentence and that the status of such Bonds and any other outstanding Bonds is not adversely affected under the Code. Notwithstanding the defeasance of any Bonds pursuant to the Resolution, the District shall remain obligated to make any payments with respect to such Bonds required to be made to the United States by Section 148 of the Code. Within 30 days following the defeasance of any 2013 Bonds pursuant to the Resolution, the District shall mail written notice of the action so taken to the owners of the defeased Bonds.

Covenants

In the Resolution the District has agreed to various covenants, including the following:

1. To Maintain the Properties of the Cowlitz Falls Project and to Keep the Cowlitz Falls Project in Good Repair. The District will, consistent with the Power Purchase Contract for the Term of the Cowlitz Falls Agreements, (a) at all times operate (unless the District is replaced as operator pursuant to the Power Purchase Contract) the properties of the Cowlitz Falls Project, including necessary transmission facilities, and the business in connection therewith in an efficient manner and at reasonable cost, (b) maintain or cause to be maintained the properties of the Cowlitz Falls Project, including necessary transmission facilities, and all improvements thereto and extensions thereof, in reasonably good repair, working order and condition, and (c) make, or cause to be made, all necessary repairs, renewals, replacements, additions, improvements and betterments thereto and extensions thereof, so that at all times the business carried on in connection therewith shall be properly and advantageously conducted.

The District will use its best efforts to comply with the terms of any permit or license for the Cowlitz Falls Project and with any federal, state or local regulation applicable to the Project, including without limitation, the FERC License.

2. Rates and Charges of the Cowlitz Falls Project. The District will establish and collect rates and charges for electric power and energy or other goods and services sold or supplied through the Cowlitz Falls Project that will be sufficient to provide the District with Cowlitz Falls Revenues sufficient for the payment of Cowlitz Falls Project Power Costs, after crediting against such costs amounts paid from the Reserve and Contingency Account or from insurance proceeds.

3. Disposition of All or Part of the Cowlitz Falls Project. Except as provided in the Power Purchase Contract, the District will not sell, mortgage, lease or otherwise dispose of or encumber all or any portion of the Cowlitz Falls Project except:

(a) The District may dispose of all or substantially all of the Cowlitz Falls Project, provided that simultaneously the District shall cause all of the Bonds to be, or deemed to be, no longer outstanding. The District may not sell or otherwise dispose of any part of the useful operating properties of the Cowlitz Falls Project if such sale or disposition would result in a reduction of Cowlitz Falls Revenues below that required to be maintained under paragraph 2 above.

(b) The District may dispose of, consistent with the terms of the Power Purchase Contract, any portion of the Cowlitz Falls Project that the Board determines to be unserviceable, inadequate, obsolete, worn out or unfit to be used or no longer required for use in connection with the operation of the Cowlitz Falls Project whether due to delay or termination of Project construction or operation. Moneys received by the District as the proceeds of any such sale, lease or other disposition shall be transferred to the Reserve Account to the extent that such transfer shall be necessary to make up any deficiency in the Reserve Account and the balance, if any, shall either (i) be used for repairs, renewals, replacements, or additions to or extensions of the Cowlitz Falls Project or (ii) be used in the retirement of a prorated portion of all outstanding Bonds as specified in the Resolution.

(c) If the ownership of all or part of the Project is transferred from the District through the operation of law, including condemnation, the District shall reconstruct or replace the portion unless the Board determines that such reconstruction or replacement is not in the best interests of the District and the bondowners, in which case any proceeds shall be used to retire Bonds prior to maturity.

4. Insurance. Subject to the terms of the Power Purchase Contract during the Term of the Cowlitz Falls Agreements, the District will either insure or self-insure the Project against risks, accidents or casualties, at least to the extent that insurance is usually carried by municipal corporations operating like properties and if such insurance is available at a reasonable cost. In the event of any loss or damage, and subject to the terms of the Power Purchase Contract during the Term of the Cowlitz Falls Agreements, the District will promptly deposit the insurance proceeds received from insurance for the Project into any construction fund hereafter created, and use such funds to repair or replace the damaged portion of the insured property or transfer the proceeds of such insurance or self-insurance funding to the Reserve Account to the extent that such transfer shall be necessary to make up any deficiency in the Reserve Account and the balance, if any, shall either (i) be used for repairs, renewals, replacements, or additions to or extensions of the Cowlitz Falls Project or (ii) be used in the retirement of Bonds prior to maturity, either by purchase at prices not to exceed the next applicable redemption price or by call for redemption.

5. Books of Account. The District shall keep proper books of account, which will be audited annually by the Washington State Auditor's office or an independent public accountant. Any bondowner may obtain at the office of the District or upon written request to the District copies of the District's annual report.

6. Protection of Security. The District shall comply with the terms of the Power Purchase Contract so long as such contract is in effect. Nothing in the Cowlitz Falls Agreements shall be amended, modified, or otherwise altered in any manner which will reduce the payments pledged as security for the Bonds or extend the time of such payments provided in the Power Purchase Contract or which will in any manner materially impair or adversely affect the rights of the owners of the Bonds.

7. Tax Covenants. The District will not take any action that will cause the 2013 Bonds to be "arbitrage bonds" under the Code.

Trustee

U.S. Bank National Association, Portland, Oregon, is appointed to act as Trustee for the owners of all Bonds. The Trustee may resign upon 45 days' notice mailed to each bondowner or published in a newspaper of general circulation or financial journal published in New York. Such resignation shall take effect upon the appointment of a

new Trustee. The Trustee may be discharged by the District as long as an Event of Default has not occurred and is continuing or by the owners of a majority of the outstanding Bonds. The consent of Bonneville shall be required for any such discharge. If the Trustee resigns or is discharged the District shall appoint a new Trustee. At any time within one year after such appointment, the Owners of a majority of the outstanding Bonds may appoint a successor Trustee, which shall supersede any Trustee appointed by the District.

Prior to the occurrence of an Event of Default and subsequent to the curing of such Event of Default, the Trustee shall not be liable except for the performance of its duties and obligations set forth in the Resolution and to act in good faith in the performance thereof, and no implied duties or obligations shall be incurred by the Trustee other than those specified in the Resolution. If an Event of Default has occurred and not been cured, the Trustee shall use the same degree of care and skill in the exercise of its duties set forth in the Resolution as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. The Trustee shall not be deemed to have knowledge of any Event of Default not known to the Trustee.

The Trustee is not responsible for the recitals of fact in the Resolution and makes no representations as to the legal validity or sufficiency of the Resolution or of any Bonds or in respect of the security afforded by the Resolution.

Any money deposited with the Paying Agent and not applied to the payment of Bonds within three years following the final maturity or redemption of the Bonds shall be transferred to the District free from the trusts created by the Resolution.

Events of Default and Remedies

1. Events of Default. The following constitute "Events of Default" under the Resolution:

(a) Default in the punctual payment of the principal of any Bond when the same shall become due;

(b) Default in the punctual payment of interest on any Bond when the same shall become due;

(c) Failure to purchase or redeem Term Bonds in a principal amount at least equal to the applicable Sinking Fund Requirement when the same shall become due;

(d) Default under any agreement with respect to a Qualified Letter of Credit or Qualified Insurance or other credit enhancement device providing security for the Bonds, which results in suspension, expiration or termination of the payment obligations of the issuer of the device and the District within ten days of such suspension, expiration or termination of payment obligations fails to obtain a substitute credit enhancement device or take other measures to remedy such default;

(e) Default in the observance of any other of the covenants and conditions in the Resolution and such default continues for 90 days after the District receives from the Trustee or from the owners of not less than 66% in principal amount of any series of Bonds outstanding a written notice specifying and demanding the cure of such default; or

(f) If the District shall admit in writing its inability to pay its debts as they become due, file a petition in bankruptcy, make an assignment for the benefit of its creditors, consent to the appointment of a receiver for the Cowlitz Falls Project; or consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of the District or of the whole or any substantial part of the Cowlitz Falls Project.

2. Payment of Funds to Trustee. If an Event of Default is not remedied, the District, upon demand of the Trustee, shall pay to the Trustee all funds held by the District and pledged under the Resolution and Cowlitz Falls Revenues upon receipt. The Trustee shall apply the funds in accordance with the Resolution.

3. Remedies. The Trustee may, if an Event of Default is not remedied, take such steps and institute such proceedings as it deems appropriate to collect all sums owing and to protect the rights of bondowners. If an Event of Default exists there is no right to accelerate payment of all or any of the interest on or principal of the Bonds not then due and payable. The owners of the Bonds shall be deemed to irrevocably appoint the Trustee as the lawful trustee of the bondowners. The owners of at least 66% in principal amount of the outstanding Bonds may, in certain circumstances, direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any power conferred upon the Trustee.

No bondowner may institute any proceeding for the enforcement of the Resolution unless an Event of Default is continuing and the owners of not less than 66% in principal amount of the outstanding Bonds have given the District and the Trustee written notice to institute such proceeding and the Trustee has refused or neglected to comply within a reasonable time.

Supplemental Resolutions

1. Supplemental Resolutions Without Consent of Bondowners. The Board may adopt a supplemental resolution authorizing the issuance of Additional Bonds or a resolution amending or supplementing the Resolution (a) to add to the covenants and agreements of the District in the Resolution other covenants and agreements that will not adversely affect the interest of the bondowners in any material way, (b) to cure any ambiguities or correct any defective provisions in the Resolution or any supplemental resolution which shall not adversely affect the bondowners' interest in any material way, or (c) to add conditions for the issuance of Additional Bonds after the Term of the Cowlitz Falls Agreements.

2. Supplemental Resolutions With Consent of Bondowners. With the consent of the owners of not less than 50% in principal amount of the outstanding Bonds, the District may adopt a resolution amending or supplementing the Resolution; provided, that, without the specific consent of the owner of each Bond that would be affected, no such supplemental resolution shall: (a) change the fixed maturity date for the payment of the principal of any Bond or the date for the payment of interest or the terms of the redemption thereof, or reduce the principal amount of any Bond or the rate of interest thereon or the redemption price (or the redemption premium) payable upon the redemption or prepayment thereof; (b) reduce the percentage of Bonds the owners of which are required to consent to any Supplemental Resolution; (c) give to any Bond any preference over any other Bond; or (d) create any pledge of the Cowlitz Falls Revenues superior or equal to the pledge of and lien and charge for the payment of the Bonds.

Consent of Bonneville

During the term of the Cowlitz Falls Agreements, any decision required to be made by the District under the Resolution shall require the concurrence of Bonneville.

APPENDIX D

SUMMARY OF THE
POWER PURCHASE CONTRACT AND THE PAYMENT AGREEMENT

POWER PURCHASE CONTRACT

A summary of certain provisions of the Power Purchase Contract between the District and Bonneville (each, a "Party" and together, the "Parties") relating to the Cowlitz Falls Project is set forth below. The summary is not to be considered a full statement of the Power Purchase Contract and is qualified by reference to the complete text of the Power Purchase Contract.

Term

The Contract is effective from the date of its execution and delivery to the District (May 23, 1991) through June 30, 2032, unless earlier terminated (the "Term").

Certain Definitions Used in the Power Purchase Contract

"Financing Costs" means the costs associated with the authorization, issuance and sale of Cowlitz Falls Bonds, including but not limited to reserve and contingency funds, working capital, capitalized interest, debt service reserve, bond discount and finance expenses, letter of credit fees, bond insurance, and fees for bond counsel, bond printing, financial advisor, Registrar/paying agent and Trustee, less any net receipts related to financing.

"Operating Year" has the same meaning as in the Resolution. See Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution."

"Operation and Maintenance Costs" has the same meaning as in the Resolution. See Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution."

"Other Renewal and Replacement Costs" has the same meaning as in the Resolution. See Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution."

"Project Output" means the entire amount of capacity and energy including test energy, less station service, generated and available at the Project during the Term.

"Project Power Costs" has the same meaning as "Cowlitz Falls Project Power Costs" in the Resolution. See Appendix C – "SUMMARY OF THE RESOLUTION – Certain Definitions Used in the Resolution."

"Special Operation and Maintenance Costs" includes costs of renewals and replacements that are not "Other Renewals and Replacements," spare parts not capitalized, labor costs (including benefits but excluding taxes), consumables, transportation expenses, and administrative and general expenses incurred to maintain and operate the Project.

"Uncontrollable Force" means an act or event beyond the reasonable control of a Party, and which by exercise of due diligence and foresight such Party could not reasonably have been expected to avoid or remove, which impairs the ability of the Party to perform, and includes, but is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, accident, fire, lightning and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities against any action taken or not taken by a Party, after a good faith effort by the appropriate Party to obtain: (i) relief from such order; or (ii) any necessary authorizations or approvals from any governmental agency or regulatory authority.

Purchase and Sale of Project Output

The District agrees to sell and deliver, and Bonneville agrees to purchase and accept delivery of, the entire Project Output during the Term, subject to the terms of the Power Purchase Contract. Bonneville agrees to pay to the District during each Operating Year (or portions thereof) of the Term an amount equal to Project Power Costs, whether or not the Project or any part thereof has been completed, terminated, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditioned upon the performance or nonperformance of any Party to any agreement for any cause whatever.

Annual Operating Budget

Commencing no later than 120 days prior to the start of each Operating Year during the Term, the Parties shall commence development of a mutually agreeable annual operating budget covering a prospective seven Operating Year period for specified Project Power Costs. Each annual operating budget shall specify the amounts and due dates for all payments from Bonneville to the District for Project Power Costs during the next two Operating Years.

Bonneville shall pay to the Trustee the portion of Project Power Costs consisting of Annual Debt Service on or before the date such amounts are due under the Resolution.

As part of the annual operating budget process the Parties shall consult and mutually agree upon the need for, timing of and means of funding any Other Renewal and Replacement Costs. Prior to the start of each annual operating budget process a relative efficiency test must be performed on the Project. After consultation with the District, Bonneville shall determine what corrective measures are needed to remedy the loss of efficiency, and shall include funding for such corrective measures in the annual operating budget. The District shall promptly implement such corrective measures.

Limitations on Certain Payments

The District's obligation to reimburse Bonneville for certain Special Operation and Maintenance Costs, and Bonneville's obligation to make incentive payments for Special Operation and Maintenance Costs, shall be limited during any Operating Year to an amount calculated by multiplying 3.6 mills per kilowatt-hour (9.5% of the District's 1988 retail rates) by the District's total retail sales (in kilowatt-hours) during the Operating Year in which the payment obligation was incurred. The cumulative limit of the District's obligation is the amount remaining in the Lewis Investment Account in the Construction Fund at the time of fund disbursements inflated by the Gross National Product Implicit Price Deflator as published by the U.S. Department of Commerce.

Point of Delivery

The District will deliver and Bonneville will receive Project Output at a point that is approximately six miles west of Tacoma City Light's Mossyrock Dam and that is in the vicinity of the Silver Creek-Cinebar County Road where the 230 kV facilities of Tacoma and Bonneville are connected with an interconnection voltage of 230 kV.

Additional Bonds

When requested by Bonneville, the District shall use its best efforts to arrange for the refinancing or refunding of Cowlitz Falls Bonds, the financing of Delay Costs, the financing of Termination Costs for site restoration, and the financing of all or any portion of any Other Renewal and Replacement Costs for the Project. Such requests by Bonneville shall not require the District to issue and sell Cowlitz Falls Bonds with maturities which are subsequent to the Term of the Contract, unless otherwise agreed to by the Parties. Bonneville shall compensate the District for all costs incurred by the District in undertaking any financing, refinancing or refunding effort. Bonneville shall withdraw any request for financing, refinancing or refunding when the District demonstrates that complying with such request will detrimentally affect its costs, or materially impair its ability, to finance facilities necessary to provide reliable service to the District's retail customers.

Consent of Bonneville

The District may not adopt any resolution, or indenture, or incur any indebtedness which constitutes a charge on the Project through which the District will acquire funds during the Term of the Power Purchase Contract to pay costs of the Project without first obtaining Bonneville's written consent.

Right of First Refusal

For the period from the expiration of the Power Purchase Contract (June 30, 2032) until the end of the Project's second FERC License, if any, or until July 1, 2066, whichever is later, Bonneville shall have the right of first refusal to purchase firm Project capability on the same terms under which the District has entered into a memorandum of sale evidencing an intention to sell firm Project capability.

Arbitration

The Parties agree to submit to binding arbitration most issues, disputes and controversies arising out of the Power Purchase Contract that the Parties have the legal authority to arbitrate and that cannot be otherwise resolved by discussions between the Parties.

Contractor Performance

All contracts between the District and Project contractors and subcontractors must require such contractors and subcontractors to perform in accordance with contract specifications. Such contracts must grant Bonneville certain audit rights and must assign to Bonneville or the Project, as appropriate, any financial penalties or payments imposed in such contracts. The Parties will make a good faith effort to provide incentives in such contracts for constructing the Project on schedule and under budget.

Uncontrollable Force

Any obligation of a Party to perform under the Power Purchase Contract shall be excused when failure to perform such obligation is due to an Uncontrollable Force; provided that a Party's obligation to pay or reimburse the other for Project Output, Project Holding Costs, and certain other payments shall not be excused. A Party must exercise due diligence to remove its inability to perform with reasonable dispatch. However, neither Party shall be required under the Power Purchase Contract to settle any strike or labor dispute in which it may be involved.

Use of Project Output

From the expiration date of the Power Purchase Contract until the later of the end of the second FERC License issued to the District to operate the Project or July 1, 2066, if and to the extent that the District is licensed to operate the Project, the District agrees to dedicate the Project's firm capability to serve the District's loads under its power sales contract in effect during such period with Bonneville or its successor.

Subject to Bonneville's election, the District is relieved of this obligation to dedicate firm capability during any Operating Year when the cost of the firm capability of the Project, calculated as set forth in the Contract, exceeds the District's cost of wholesale power purchased from Bonneville.

Assignment

Each of the Parties agrees that it will not sell, assign or transfer its interests, rights or obligations under the Power Purchase Contract except to any corporation or entity required or permitted under the Resolution or so long as the Cowlitz Falls Bonds are outstanding, to any corporation or other entity approved by the other Party. In addition, Bonneville may sell, assign, transfer or otherwise dispose of Project Output in any manner in its sole discretion. Notice of any such assignment or transfer by a Party must be given to the other Party as provided in the Power Purchase Contract. The Power Purchase Contract inures to the benefit of and will be binding on the successors and assigns of the Parties.

PAYMENT AGREEMENT

A summary of certain provisions of the Payment Agreement between Bonneville and the Trustee relating to the Cowlitz Falls Project is set forth below. The summary is not to be considered a full statement of the Payment Agreement and is qualified by reference to the complete text of the Payment Agreement.

Payment Obligation

The Payment Agreement provides that if and to the extent that Bonneville does not make payments of debt service on the Cowlitz Falls Bonds at the time and in the manner described by the Power Purchase Contract, Bonneville will make such payments not later than the dates on which such payments are described by the provisions of the Power Purchase Contract. To the extent the amounts required to be paid under the Resolution as principal and interest due and payable on the Cowlitz Falls Bonds will not be available in the Bond Fund to be paid when due, Bonneville will make such payments to the Trustee for the benefit of the bondowners. Such payments shall be made at the time and place and in such manner as to enable the payments to bondowners to be made on the dates required by the Resolution. All payments required to be made by Bonneville under the Payment Agreement will be made solely from the Bonneville Fund or from such other funds as shall now or hereafter become legally available for such purposes.

The Payment Agreement does not affect the rights of the District, the Trustee or the bondowners under the Resolution. The Payment Agreement serves as further security for the Cowlitz Falls Bonds (in addition to the security provided for by the Resolution and the Power Purchase Contract) and will remain in full force and effect without impairment of any of its obligations until the earlier of termination of the Power Purchase Contract according to its terms or the date on which no Cowlitz Falls Bonds remain outstanding.

Default and Remedies

The Trustee has the right to enforce the Payment Agreement and to protect the interest of the bondowners in the manner provided by law. In the event of a default under the Payment Agreement, the Trustee may proceed first and directly against the United States without proceeding against any other person, without exhausting any other remedies that it may have and without resorting to any other security held by the District or the Trustee. There is no right to acceleration of any payment obligation due under the Payment Agreement.

The Payment Agreement is not a guaranty, and Bonneville waives any defense of presentment, demand for payment, protest, division, discussion or notice of nonpayment or dishonor and all other defenses whatsoever based upon notices or demands relating to the Cowlitz Falls Bonds. In addition, no set-off, counterclaim, reduction or diminution of any obligation or any defense of any kind or nature (other than performance by Bonneville of its obligations under the Payment Agreement) that Bonneville may have or assert against the District, the Trustee or any bondowner is available under the Payment Agreement.

Bonneville will pay all costs, expenses and fees, including all reasonable attorneys' fees, that the Trustee may incur in enforcing or attempting to enforce the Payment Agreement.

Bonneville has no recourse against the District under the Payment Agreement for any payment, or the performance of any other obligation, made by Bonneville pursuant to the Payment Agreement. This provision does not affect the rights of Bonneville or the District under the Power Purchase Contract.

In the event that a decision is entered by any court of competent jurisdiction rendering the Power Purchase Contract unenforceable in any respect deemed material by Bonneville, Bonneville has the option to direct the termination of the Project and/or the redemption of part or all of the Cowlitz Falls Bonds outstanding, all according to the procedures prescribed by the Power Purchase Contract and the Resolution. Such termination will be effected as if initiated by Bonneville pursuant to the Power Purchase Contract. All funds held by the Trustee or the District that are proceeds of the Cowlitz Falls Bonds not otherwise committed (and that are legally available for such purposes) may, at Bonneville's option, be applied to the costs of such redemption with the exception of moneys received by the District pursuant to the Power Purchase Contract as reimbursement for Lewis' Investment (as defined in the

Power Purchase Contract) in the Project. To the extent that such funds are not sufficient to cover the costs of any such redemption of the Cowlitz Falls Bonds, Bonneville will pay the balance of such costs.

If the Project is so terminated, all costs of such termination, including, but not limited to, compensation or damages payable to all contractors and the costs of site restoration and environmental mitigation, as required by law or regulatory order, shall be paid by Bonneville.

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APPENDIX E

PROPOSED FORM OF OPINION OF BOND COUNSEL

Public Utility District No. 1
of Lewis County, Washington

Re: Public Utility District No. 1 of Lewis County, Washington
Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 - $87,995,000

Ladies and Gentlemen:

We have served as bond counsel to Public Utility District No. 1 of Lewis County, Washington (the "District"), and have examined a certified transcript of all of the proceedings taken in the matter of the issuance by the District of its Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013, in the aggregate principal amount of $87,995,000 (the "2013 Bonds"), and in that capacity have examined such law and such certified proceedings and other documents as we have deemed necessary to render this opinion. As to matters of fact material to this opinion, we have relied upon representations contained in the certified proceedings and other certifications of public officials furnished to us, without undertaking to verify the same by independent investigation.

The 2013 Bonds are issued by the District pursuant to Resolution No. 2245 adopted on June 19, 2003 (the "2003 Resolution"), as supplemented by Resolution No. 2612 adopted on May 13, 2013 (the "First Supplemental Resolution," and together with the 2003 Resolution, the "Resolution") to provide funds to refund the District's outstanding Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 (the "2003 Bonds") maturing on and after October 1, 2014, and pay costs of issuance of the 2013 Bonds, all as set forth in the Resolution.

The 2013 Bonds are subject to redemption prior to their stated maturities as set forth in the Resolution.

Reference is made to the 2013 Bonds and the Resolution for the definitions of capitalized terms used and not otherwise defined herein.

As to questions of fact material to our opinion, we have relied upon the certified proceedings and other certifications of public officials furnished to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date of initial delivery of the 2013 Bonds to the purchaser thereof and full payment therefor, it is our opinion that under existing law:

1. The District has the right and power under Title 54 of the Revised Code of Washington (the "Act") to adopt the Resolution. The Resolution has been duly and lawfully adopted by the District, is in full force and effect, is valid and binding upon the District and is enforceable in accordance with its terms.

2. The Resolution creates valid pledges of (i) Cowlitz Falls Revenues, which include all income, revenue and payments derived by the District in connection with the Cowlitz Falls Project, together with the proceeds received by the District directly or indirectly from the sale, lease or other disposition of any of the properties, rights or facilities of the Project and certain other money, including payments received or receivable pursuant to the Power Purchase Contract, exclusive of any payments received under the Payment Agreement, certain insurance proceeds, and income pledged to the defeasance of specific revenue bonds, and (ii) money and assets, if any, credited to the Cowlitz Falls Project Revenue Fund, the Bond Fund, or any junior lien fund except proceeds from junior lien obligations, exclusive of money to be rebated to the federal government. Such pledges constitute a lien and charge equal in rank to the lien on such proceeds, revenues, money and securities required to pay and secure

obligations issued on a parity with the 2013 Bonds and the 2003 Bonds and are superior to all other charges of any kind or nature.

3. The District is duly authorized and entitled to issue the 2013 Bonds, and the 2013 Bonds have been duly and validly authorized and issued by the District in accordance with the laws of the State of Washington, including the Act. The 2013 Bonds constitute the valid and binding obligations of the District as provided in the Resolution, are enforceable in accordance with their terms and the terms of the Resolution and are entitled to the benefits of the Act and the Resolution. The 2013 Bonds are special limited obligations of the District and neither the State of Washington nor any political subdivision thereof, other than the District, is obligated to pay the principal of and interest on the 2013 Bonds, except to the extent that the enforcement of the rights and remedies of such owner of the 2013 Bonds may be limited by laws relating to bankruptcy, insolvency, moratorium, reorganization or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and by the exercise of judicial discretion.

4. The 2013 Bonds are not general obligations of the District.

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

We bring to your attention the fact that the foregoing opinions are expressions of our professional judgment on the matters expressly addressed and do not constitute guarantees of result.

Respectfully submitted,

APPENDIX F

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE 2013 BONDS

Public Utility District No. 1 of Lewis County, Washington
321 Northwest Pacific Avenue
Chehalis, Washington 98532

Public Utility District No. 1 of Lewis County, Washington
$87,995,000
Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Public Utility District No. 1 of Lewis County, Washington (the "District"), a municipal corporation under the constitution and laws of the State of Washington, of $87,995,000 aggregate principal amount of Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 (the "2013 Bonds").

The 2013 Bonds are being issued pursuant to Title 54 and Chapter 39.53 of the Revised Code of Washington (the "Act") and Resolution No. 2245 of the District, adopted on June 19, 2003 (the "2003 Resolution"), as supplemented by Resolution No. 2612 of the District, adopted on May 13, 2013 (the "First Supplemental Resolution" and together with the 2003 Resolution, the "Resolution") to provide the funds to refund all of the District's outstanding Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2003 that mature on or after October 1, 2014, and to pay costs of issuing the 2013 Bonds.

In such connection, we have reviewed certified copies of the Resolution, the Tax Matters Certificate executed and delivered by the District on the date hereof and the Tax Matters Certificate executed and delivered by the Bonneville Power Administration on the date hereof (collectively, the "Tax Certificates"); the opinions of Foster Pepper PLLC, as Bond Counsel, dated the date hereof (the "Bond Counsel Opinions"); additional certificates of the District, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings, a procedure and methodology, and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the 2013 Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, all parties. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the third paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolution and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the 2013 Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the 2013 Bonds, the Resolution and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Our services did not include financial or other non-legal advice. Finally, as

Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of the District, dated June 13, 2013 relating to the 2013 Bonds, or other offering material relating to those 2013 Bonds and express no opinion with respect thereto.

We have relied with your consent on the Bond Counsel Opinions with respect to the validity of the 2013 Bonds and with respect to the due authorization and issuance of the 2013 Bonds.

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

1. Interest on the 2013 Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 and Section 9(f) of the Pacific Northwest Power Planning and Conservation Act, Public Law 96-501.

2. Interest on the 2013 Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. We observe, however, that interest on the 2013 Bonds is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2013 Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

APPENDIX G

FORM OF THE CONTINUING DISCLOSURE AGREEMENT

This Continuing Disclosure Agreement, dated July 10, 2013 (the "Disclosure Agreement"), made by Public Utility District No. 1 of Lewis County, Washington (the "District"), as issuer of the Cowlitz Falls Hydroelectric Project Revenue Refunding Bonds, Series 2013 (the "2013 Bonds"), and by the Bonneville Power Administration ("Bonneville") as an "obligated person" under Rule 15c2-12 of the Securities and Exchange Commission (the "Rule") with respect to the 2013 Bonds, constitutes a written undertaking by the District and Bonneville, as required by Section (b)(5) of the Rule, for the benefit of the Owners and Beneficial Owners of the 2013 Bonds.

The 2013 Bonds are issued pursuant to Resolution No. 2245 of the Board of Commissioners of the District adopted on June 19, 2003 (the "2003 Resolution"), as supplemented by Resolution No. 2612 of the Board of Commissioners of the District adopted on May 13, 2013 (the "Supplemental Resolution," and together with the 2003 Resolution, the "Resolution"). Capitalized terms not otherwise defined in this Disclosure Agreement shall have the meanings given such terms in the Resolution.

(1) Definitions.

In addition to the definitions set forth in the Resolution and in the preamble to this Disclosure Agreement, the following capitalized terms shall have the following meanings:

"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 2013 Bonds, including persons holding 2013 Bonds through nominees or depositories.

"Bonneville" means the Bonneville Power Administration.

"BPA Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2013 Bonds in the following tables in Appendix A under the heading "THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS": "Federal System Statement of Revenues and Expenses" and "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments."

"District Annual Information" means the audited financial statements of the District prepared in accordance with generally accepted accounting principles applicable to government entities, with regulations prescribed by the Washington State Auditor pursuant to RCW 43.09.200 (or any successor statute).

"District Fiscal Year" means the fiscal year ending each December 31 or, if such fiscal year end is changed, on such new date; provided that if the District Fiscal Year end is changed, the District shall provide written notice of such change to the MSRB.

"FCRPS" shall mean the Federal Columbia River Power System.

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

"MSRB" means the Municipal Securities Rulemaking Board or any successors to its functions.

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

(2) Financial Information.

(A) *Bonneville*. Bonneville agrees to provide to the MSRB, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2013:

(i) the BPA Annual Information for the FCRPS Fiscal Year;

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

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

Bonneville shall notify the District when such BPA Annual Information has been provided and when such financial statements have been provided.

(B) *District*. The District agrees to provide to the MSRB, no later than the last day of the ninth month after the end of each District Fiscal Year, commencing with the District Fiscal Year ending December 31, 2013:

(i) the District Annual Information for the District Fiscal Year; and

(ii) if the annual financial statements provided in accordance with subparagraph (i) above are not its audited annual financial statements, the District shall provide its audited annual financial statements when and if they become available.

(C) *Cross-Reference*. In lieu of providing the annual financial information and operating data described in A and B above, Bonneville and the District may specifically cross-reference other documents available to the public on the internet website of the MSRB, or filed with the SEC.

(D) *Notice of Failure to Provide Financial Information*. The District agrees to provide or cause to be provided, in a timely manner, to the MSRB, (i) notice of Bonneville's failure to provide the annual financial information described in A above on or prior to the applicable date set forth in A above, and (ii) notice of the District's failure to provide the annual financial information described in B above on or prior to the applicable date set forth in B above.

(3) Events Notices.

The District agrees to provide or cause to be provided, in a timely manner (not in excess of ten business days after the occurrence of the event), to the MSRB, notice of the occurrence of any of the following events with respect to the 2013 Bonds:

(A) Principal and interest payment delinquencies;

(B) Non payment related defaults, if material;

(C) Unscheduled draws on debt service reserves reflecting financial difficulties;

(D) Unscheduled draws on credit enhancements reflecting financial difficulties;

(E) Substitution of credit or liquidity providers, or their failure to perform;

(F) Adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notice of Proposed Issue (IRS Form 5701 – TEB) or other material notices or determinations with respect to the tax status of the 2013 Bonds;

(G) Modifications to rights of 2013 bondowners, if material;

(H) Bond calls (other than scheduled sinking fund redemptions), if material, and tender offers;

(I) Defeasances;

(J) Release, substitution or sale of property securing repayment of the 2013 Bonds, if material;

(K) Rating changes;

(L) Bankruptcy, insolvency, receivership or similar event of the District, as such Bankruptcy Events are defined in the Rule;

(M) The consummation of a merger, consolidation or acquisition involving the District or the sale of all or substantially all of the assets of the District, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and

(N) Appointment of a successor or additional trustee or the change of name of a trustee, if material.

Solely for purposes of disclosure, and not intending to modify this undertaking, the District advises with reference to items C, E and J above that no debt service reserves, property or liquidity facilities secure payment of the 2013 Bonds.

(4) Availability of Information from the MSRB.

The District and Bonneville have agreed to provide the foregoing information only to the MSRB. The information filed with the MSRB is available to the public without charge through an internet portal.

(5) Termination, Modification.

The obligations of Bonneville and the District to provide annual financial information and the obligation of the District to provide notices of events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2013 Bonds. This Disclosure Agreement, or any provision hereof, shall be null and void if Bonneville and the District: (A) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule that require this Disclosure Agreement, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the 2013 Bonds; and (B) notifies the MSRB of such opinion and the cancellation of this Disclosure Agreement.

Notwithstanding any other provision of this Disclosure Agreement, Bonneville and the District may amend this Disclosure Agreement, and any provision of this Disclosure Agreement may be waived, with an approving opinion of nationally recognized bond counsel and in accordance with the Rule.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, Bonneville and the District shall describe such amendment in each of their next annual reports, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville or the District, as applicable. In addition, if the amendment relates to the accounting principles to be

followed in preparing financial statements, (A) notice of such change shall be given in the same manner as for a material event under Section 3, and (B) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

(6) Remedies.

The right of any Owner or Beneficial Owner of 2013 Bonds to enforce the provisions of this Disclosure Agreement against the District shall be limited to a right to obtain specific enforcement of the District's obligations hereunder, and any failure by the District to comply with the provisions of this Disclosure Agreement shall not be an event of default under the Resolution or with respect to the 2013 Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Disclosure Agreement. Owners and Beneficial Owners of 2013 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

(7) Miscellaneous.

(A) *Disclaimer*. Bonneville and the District shall each be obligated to perform only those duties expressly provided for it under this Disclosure Agreement, and neither Bonneville nor the District shall be obligated to perform or monitor the performance of any duties of the other under this Disclosure Agreement.

(B) *Governing Law*. This Disclosure Agreement shall be governed by the laws of the State of Washington with respect to the District and by federal law with respect to Bonneville.

(C) *Counterparts*. This Disclosure Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all shall together constitute one and the same instrument.

IN WITNESS WHEREOF, the undersigned have duly authorized, executed and delivered this Disclosure Agreement as of the date first above written.

BONNEVILLE POWER ADMINISTRATION

By _____
Claudia R. Andrews
Executive Vice President and Chief Financial Officer

PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY, WASHINGTON

By _____
Rich Bauer,
Treasurer/Chief Financial Officer

APPENDIX H

BOOK-ENTRY ONLY SYSTEM

The following information (except for the final paragraph) has been provided by The Depository Trust Company, New York, New York ("DTC"). The District makes no representation regarding the accuracy or completeness thereof. Beneficial Owners should confirm the following with DTC or the DTC Participants (as hereinafter defined).

DTC will act as securities depository for the 2013 Bonds. The 2013 Bonds will be issued as fully-registered securities 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 bond certificate will be issued for each maturity of the 2013 Bonds, each in the aggregate principal amount of such maturity, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's rating of AA+. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of 2013 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the 2013 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2013 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 2013 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 2013 Bonds, except in the event that use of the book-entry system for the 2013 Bonds is discontinued.

To facilitate subsequent transfers, all 2013 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 2013 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 2013 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2013 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.

Redemption notices shall be sent to DTC. If less than all of the 2013 Bonds within a maturity are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to 2013 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 District 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 2013 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Payments on the 2013 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 detailed information from the District or the Registrar, on payable date 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 Registrar, or the District, subject to any statutory or regulatory requirements as may be in effect from time to time. Payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) are the responsibility of the District or the Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as depository with respect to the 2013 Bonds at any time by giving reasonable notice to the District or the Registrar. Under such circumstances, in the event that a successor depository is not obtained, 2013 Bond certificates are required to be printed and delivered.

The District may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository). In that event, 2013 Bond certificates will be printed and delivered to DTC.

The information in this appendix concerning DTC and DTC's book-entry system has been obtained from sources that the District believes to be reliable, but the District takes no responsibility for the accuracy thereof.

Neither the District nor the Registrar will have any responsibility or obligation to DTC participants or the persons for whom they act as nominees with respect to the 2013 Bonds for the accuracy of any records maintained by DTC or any DTC participant, the payment by DTC or any DTC participant of any amount in respect of the principal of or interest on 2013 Bonds, any notice that is permitted or required to be given to Registered Owners under the Resolution (except such notices as shall be required to be given by the District to the Registrar or to DTC), the selection by DTC or any DTC participant of any person to receive payment in the event of a partial redemption of the 2013 Bonds, or any consent given or other action taken by DTC as the Registered Owner. For so long as any 2013 Bonds are held in book-entry only form, DTC or its nominee shall be deemed to be the Registered Owner for all purposes, and all references in the Resolution to the Registered Owners shall mean DTC or its nominee and shall not mean the Beneficial Owners of any 2013 Bonds.

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PUBLIC UTILITY DISTRICT NO. 1 OF LEWIS COUNTY, WASHINGTON • COWLITZ FALLS HYDROELECTRIC PROJECT REVENUE REFUNDING BONDS, SERIES 2013

Lewis PUD PUBLIC UTILITY DISTRICT County

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